Canada. National Energy Board

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NATIONAL ENERGY BOARD

REPORT TO

THE GOVERNOR IN COUNCIL

In the Matter of the Applications under

The National Energy Board Act of

Trans-Canada Pipe Lines Limited
Alberta and Southern Gas Co. Ltd.
Alberta Natural Gas Company
Westcoast Transmission Company Limited
Canadian-Montana Pipe Line Company [and]
Niagara Gas Transmission Limited

[Ottawa, Queen's Printer]

March, 1960

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APPENDICES

SECTION 1

INTRODUCTION

The Board, in accordance with the authority conferred upon it by the National Energy Board Act, conducted a public hearing from January 5, 1960 to February 12, 1960 on

applications under Part VI of the Act by Trans-Canada Pipe Lines Limited (hereinafter called "Trans-Canada"), Alberta and Southern Gas Co. Ltd. (hereinafter called "Alberta and Southern"), Westcoast Transmission Company Limited (hereinafter called "Westcoast"), Canadian-Montana Pipe Line Company (hereinafter called "Canadian-Montana"), Niagara Gas Transmission Limited (hereinafter called "Niagara Gas") for licences to export gas from Canada and related applications under Part III of the Act by Trans-Canada, Alberta Natural Gas Company (hereinafter called "Alberta Natural"), Canadian-Montana, and Niagara Gas for certificates of public convenience and necessity to construct and operate pipe lines for the transmission of the gas to be exported.

By unanimous consent of counsel for the various

applicants at a pre-hearing conference with the Board and pursuant to the Board's Orders GH-1-59 and GH-2-59 issued November 20 and 24, 1959 respectively, the applications were heard jointly.

These applications for licences seek permission to export approximately 6.7 trillion cubic feet of natural gas to various areas of the United States and an indeterminate volume, not exceeding 204 million cubic feet on any day, of interruptible gas. Particulars of the volumes of gas and the proposed export period in the specific applications are set out below:

	Millions of Cubic Feet			
Company	Maximum Day	Total Annual	Total Volume	Period of Licence Applied For
Trans-Canada at Emerson	204.0	74,000.	1,410,000.	Period ending 14 May 1981
and at Niagara Falls	204.0			Period ending 14 May 1981
Alberta and Southern	458.75	153,270.	3,826,000.	25 years from first export
Canadian-Montana	36.0	10,950.	273,750.	25 years from first export
Westcoast	165.0	54,000.	1,100,000.	20 years following first export or February 29, 1984, whichever is the sooner
Niagara Gas	16.71	3,765.7	73,521.75	Period ending 30 June 1980.
		TOTAL	6,683,271.75	

By agreement, each applicant for an export licence submitted estimates of future requirements for natural gas in Canada and evidence on present and future Canadian reserves of gas before presenting details of its particular application. It is proposed to assess this evidence, which purported to show that the supplies of gas involved in the applications for export licences are surplus to Canadian requirements, before reviewing the particular case of each applicant.

SECTION 2

CANADIAN MARKETS

Trans-Canada and Alberta and Southern presented to the Board estimates of foreseeable Canadian requirements for gas in Quebec, Ontario and Manitoba. Trans-Canada is the sole supplier of gas to these provinces, except for relatively small amounts produced in or imported into the southwestern portion of Ontario. This company developed a detailed sales forecast reflecting current contracted commitments to distributors and additional sales under negotiation for the market areas it serves. Various distributors which are supplied by Trans-Canada in Ontario and Quebec appeared in support of the long-term projection which Trans-Canada derived by trending its sales in these market areas. The company's estimate of the requirements of the southwestern portion of Ontario which draws supplies of gas from other sources as well as from Trans-Canada, was supported by Union Gas Company of Canada Limited (hereinafter called "Union Gas"). This company and its subsidiaries distribute and store gas in this area. The estimates of future requirements for gas in Quebec, Ontario and Manitoba submitted by Alberta and Southern were prepared by Economic Research Corporation and Stanford Research Institute from a market survey conducted in 1958 by those organizations.

Estimates of Saskatchewan requirements prepared by The Fish Corporation Limited, of Alberta requirements published by the Alberta Oil and Gas Conservation Board (hereinafter called the "Alberta Board") and Westcoast's estimate of British Columbia requirements were adopted by both Trans-Canada and Alberta and Southern for purposes of an overall estimate of Canadian requirements.

Westcoast, in association with British Columbia Electric Company Limited (hereinafter called "B.C. Electric") and Inland Natural Gas Co. Ltd. (hereinafter called "Inland"), the major distributors of natural gas in British Columbia, estimated the growth of requirements in that province for the 5-year period 1960 to 1964. Westcoast's projection of provincial requirements to the year 1989, in addition to estimating probable growth in demand for gas in the established market areas of its distributors, included a provision for gas supply to areas in Vancouver Island and to small communities in northern areas of British Columbia and in the East Kootenay District. The company adopted the evidence submitted by Alberta and Southern with reference to future requirements elsewhere in Canada.

Canadian-Montana adopted the estimate of Canadian requirements presented by Alberta and Southern while Niagara Gas relied upon the estimates submitted by Trans-Canada.

In preparing its own estimate of foreseeable requirements for natural gas in Canada the Board also had at its disposal estimates of Canada's future energy requirements prepared by officials of various Departments of the Government of Canada. At an early stage in its work the Board arranged for an historical study of the uses of energy in Canada from 1945 to 1958 and for projections by provinces of the use of the different forms of energy to 1965, 1975 and 1985. This work is being carried out by the Dominion Coal Board in close association with the National Energy Board. In addition, a forecast of the use of gas was undertaken by staff loaned to the Board from the Department of Trade and Commerce in association with officials of the Department of Mines and Technical Surveys.

The general forecast on energy is not yet completed for publication but it has served a most useful purpose in suggesting the role which natural gas may play in meeting the general energy requirements of Canada. The staff forecast on foreseeable gas requirements appears as Appendix 4.

In making its estimate of the foreseeable requirements for gas in Canada the Board also has had reference to the interventions of the Saskatchewan Power Corporation (hereinafter called "Saskatchewan Power") and of B.C. Electric. Saskatchewan Power contended that the requirements of the Province of Saskatchewan would be substantially

greater than the estimate prepared by The Fish Corporation Limited. Saskatchewan Power estimated total gas requirements for the Province of Saskatchewan for the years 1960 to 1989 inclusive, to be 4.5 trillion cubic feet. This contrasts with 1.3 trillion cubic feet included in the estimate of Trans-Canada and Alberta and Southern for the same market.

B.C. Electric contended that its requirements for gas for thermal electric generation purposes would be higher than were allowed for by Westcoast in its estimate of the British Columbia markets. Whereas Westcoast had anticipated supplying the company with 17,520 million cubic feet per annum from 1965 to 1989 for power purposes, B.C. Electric indicated a requirement of 28,032 million cubic feet.

The Board's estimate of annual demand for natural gas in the various provinces of Canada for the period 1960 to 1989 inclusive appears in Table 1. It will be seen that annual demand is expected to rise from approximately 365 billion cubic feet in 1960 to approximately 1.6 trillion cubic feet in 1989. The cumulative requirements from 1960 to 1989 inclusive are estimated to be approximately 30 trillion cubic feet.

The Board has concluded that the estimate of requirements in Canadian markets east of British Columbia suggested by Alberta and Southern may have under-estimated the potential sales of gas in these areas, notably for industrial purposes in Ontario. The staff estimate of requirements in these market areas while differing in a number of respects was in close agreement with Trans-Canada's estimate of total cumulative requirements over the period 1960 to 1989. The Board's estimate for these Canadian markets covering the 30-year period is approximately 750 billion cubic feet higher than Trans-Canada's forecast requirement, the difference largely arising from the Board's higher figures for Saskatchewan. The Board has accepted a staff estimate of some 2 trillion cubic feet. It does not concur in the estimated requirement of 4.5 trillion cubic feet proposed by Saskatchewan Power.

The Board's estimate of cumulative requirements of approximately 3.4 trillion cubic feet for the Province of British Columbia is nearly 400 billion cubic feet higher than Westcoast's estimate. The difference arises from the Board's higher estimate of industrial requirements in British Columbia, due largely to the inclusion of 28 billion cubic feet per annum from 1965 to 1989 for the generation of electric power. The Board concluded that the request of

B.C. Electric for a reservation for its future use of this volume of gas was not unreasonable and must be considered a foreseeable requirement of the Province of British Columbia.

Although it is necessary to estimate future Canadian demand for gas in detail and distinguish potential requirements for different uses, for individual provinces and for each year in the period of the forecast, the Board does not anticipate that the pattern indicated in its estimate will materialize in exactly the manner set forth in Table 1. The Board has been particularly concerned with total volumes rather than with any differences which may develop in the pattern of demand between provinces, in categories of use or in the volume of sales in any particular year. The Board is satisfied that the forecast of annual volumes and the cumulative total of Canadian requirements for the period to 1989 are reasonable figures. It is proposed to relate these figures to estimates of gas reserves for the purpose of determining security of supply in Canada and the volume of reserves which can be considered surplus to Canadian foreseeable requirements.

SECTION 3

NATURAL GAS RESERVES

Considerable evidence concerning Canadian geology and its implications for probable occurrences of natural gas in Canada was placed before the Board during the hearings. This material was related to present and future gas reserves and was submitted by applicants and other interested parties. It was reviewed and incorporated into the geological study appearing in Appendix 5 carried out by the staff of the Board.

In order to determine the present reserves of natural gas in Canada, it is first necessary to establish a base from which to measure and evaluate the evidence concerning these reserves. Furthermore, it is most desirable that this base be used to equate the data of various estimators, one with the other, as well as with other information.

Some applicants have adopted the estimates of the Alberta Board for certain fields in that province. The reserves estimates as prepared by the Alberta Board constitute the only available data on a large number of fields. It is necessary at this time to employ a method of assessing reserves so that the historical data on Alberta may be used to forecast the trends in future discoveries since that

province has the largest percentage of established reserves and the longest experience of production and development in Canada.

Established Reserves

The National Energy Board has decided to employ the concept of "established reserves". The term "established reserves" as defined by the Alberta Board and as adopted by this Board, means: "reserves which can be considered established in the sense that their existence and estimated amounts can reasonably be counted upon". Established reserves have been determined by crediting 100 per cent of proven reserves plus a varying percentage, not exceeding 50, of probable reserves. Probable reserves are estimated where there is not sufficient well control to justify proven status, by taking into consideration known geology, previous experience with similar types of reservoirs, and seismic data if available. No probable reserves have been allocated to either one-well discoveries or fully developed pools.

In a review of the gas reserves estimates submitted at the hearings, the Board found some divergent opinions concerning individual fields. In most instances the engineers and geologists followed the same methods of calculation but some of the factors differed to such an extent that the end results varied considerably.

Evidence respecting reserves estimates for twelve Alberta fields from which Trans-Canada has contracted for the purchase of gas was submitted by Messrs. Horte, Leslie, and Foo, all employed by that company. These estimates differed from those published by the Alberta Board. However, Trans-Canada adopted the reserves estimates on 15 other fields as published in the September 1958 or March 1959 reports of the Alberta Board. Trans-Canada also submitted totals for Alberta, Saskatchewan and Ontario.

Mr. Wege of Ralph E. Davis and Associates, on behalf of Alberta and Southern, presented reservoir studies covering the 22 fields under contract or option to his clients. He estimated proven reserves of 5.4 trillion cubic feet and probable reserves of 1.3 trillion cubic feet, a total of 6.7 trillion cubic feet. When questioned as to how much reliance could be placed on his estimated probable reserves, he stated that as far as individual field estimates were concerned, he was not prepared to indicate the degree of reliance but considering the fields as a whole, he was confident that his total estimated probable reserves would become proven after additional development. In comparing the estimates of this Board with those of Mr. Wege, there is a significant difference in the estimates for one-well pools. The totals of Mr. Wege's estimates for 11 one-well pools of

573 billion cubic feet proven and 568 billion cubic feet probable, compare with the Board's estimate of 439 billion cubic feet of established reserves.

Mr. Smith of Alberta and Southern submitted estimates of total gas reserves for British Columbia, Alberta and Saskatchewan, in giving his evidence on trends.

Dr. McPherson of McPherson-Hale Consultants Limited, on behalf of Westcoast, reviewed the recent developments in the Calgary field and submitted an estimate of those reserves. Dr. Hume and Mr. Kutney of Westcoast presented data respecting Savanna Creek.

Estimates of reserves with respect to 47 fields in northeastern British Columbia were submitted by Messrs. Hume and Kutney. Board Counsel conducted a detailed cross-examination of these two witnesses on their evidence of proven and probable areas assigned to the different fields.

A summary of proven natural gas reserves of Canada by provinces was included in the submission of the Canadian Petroleum Association (hereinafter called "CPA").

Published reserves data of various provincial bodies were available to the Board. Technical information was made freely available by the Department of Mines of British Columbia and by the Alberta Board.

The National Energy Board has reviewed all the information with respect to the fields in British Columbia

and estimates the established reserves to be 2,200 billion cubic feet as compared with the estimate of proven and probable reserves submitted by Messrs. Hume and Kutney of 3,140 billion cubic feet.

Evidence relating to 34 fields in Alberta was presented to the Board and reviewed in detail. These fields represented a good cross-section of the gas fields in the province and the estimates made by the Board were in reasonably close agreement with the estimates of the Alberta Board for the same fields. The Board adopted the reserves estimates of the Alberta Board for the remainder of the fields in that province. The Board's estimate of established reserves in Alberta is 26.9 trillion cubic feet as compared with the Alberta Board's figure of 27.1 trillion cubic feet.

For Saskatchewan and Ontario, the Board considered the summarized data submitted at the hearing, and reserve summaries published by government agencies of those provinces.

Finding on Established Reserves

The Board, having regard to the evidence, its own knowledge and the advice of its staff, has estimated the total Canadian established reserves of natural gas, as at December 31, 1959, to be 30.3 trillion cubic feet. This estimate is based on gas measured at 14.73 psia pressure base and a 60° Fahrenheit temperature base and having a heating

value of 1,000 btus per cubic foot. Details of the estimate appear in Table 3.

Trends in Exploration and Growth

There are two general methods which have been used by estimators in forecasting the development of reserves of oil and gas: the geological method and the statistical method. Each will be reviewed in so far as it relates to the future reserves of natural gas in Canada.

Geological Forecasts: The geological method relates the volume of sediments in a given basin to the ultimate crude oil reserves found therein. Reserves of natural gas are then related to those of crude oil. This approach has been employed in the United States where a relatively long history has provided reliable yardsticks. The method has also been used by regulatory bodies and the oil and gas industry in Canada in evidence placed before the Gordon and Borden Royal Commissions. It has been estimated that each cubic mile of sedimentary rocks will contain, on the average, between 30,000 and 50,000 barrels of crude oil. It is also known that the finding ratio of crude oil to natural gas in Western Canada has been approximately 6,000 cubic feet of gas for each barrel of crude oil.

The CPA in its brief to the Royal Commission on Energy predicted that with proper incentives the ultimate

reserves of gas discovered in the Western Canada basin would be in the order of 300 trillion cubic feet. This figure was determined by using:

(a) a ratio of 50,000 barrels of oil per cubic mile of sediments (based on experience in the United States);

(b) a ratio of 6,000 cubic feet of gas to each barrel of oil discovery; and

(c) 956,738 cubic miles of sediments in the Western Canada basin located as follows:

	Area Square Miles	Volume of Sediments (thickness - 1,000 to 16,000 feet) Cubic Miles
Manitoba and Saskatchewan	176,623	168,072
Alberta Plains	223,697	301,731
Alberta Foothills	13,196	39,984
British Columbia Plains	36,026	70,892
British Columbia Foothills		
- South	2,095	6,348
- North	12,567	38,078
Yukon	43,000	64,500
Northwest Territories	204,794	267,133
Total	711,998	956,738

CPA divided the ultimate reserves of 300 trillion cubic feet among the provinces and territories as follows:

	Trillions of Cubic Feet
Manitoba and Saskatchewan	5
Alberta	150
British Columbia	75
Northwest Territories and Yukon	70
Total	300

Later, CPA modified its forecast of ultimate reserves concerning Alberta and northeastern British Columbia, reducing the total for these two provinces to 185 trillion cubic feet.

Dr. Hume, referring to the CPA submission, suggested that the ultimate reserves of northeastern British Columbia would be 75 trillion cubic feet of gas and 12.5 billion barrels of oil as a possible maximum; 60 trillion cubic feet of gas and 10 billion barrels of oil as a possible minimum.

Statistical Forecasts: For several years the Alberta Board has used the statistical method of estimating the growth of reserves in that province. Data on exploratory drilling, the volume of disposable gas reserves and the

appreciation of new discoveries are employed in establishing trends that can be used in predicting the future growth of reserves. The oil and gas industry has also used the same approach.

Before this Board the applicants used the statistical method to forecast estimated cumulative disposable reserves to different years. These estimates, together with those of the Alberta Board and this Board are shown in Table 4.

Board's Estimate of Trends

Alberta: This Board's estimate of established reserves for Alberta is in close agreement with that published by the Alberta Board in its report of December 1959. It also agrees with the Alberta Board's method of projecting estimates of future growth in Alberta reserves. The overall growth of these reserves has been consistent at a rate of about 2.9 trillion cubic feet per year.

As of September 30, 1959, the drilling of 4,754 wildcat wells in Alberta (one for every 42 square miles of the 200,000 square miles of potential gas area) has resulted in the discovery of 27,829 billion cubic feet of initial disposable reserves, resulting in an overall discovery rate of 5.86 billion cubic feet per wildcat well. Experience has shown that a time lag of several years occurs before the

fields and areas evaluated in a given reserve estimate are fully developed.

In Appendix B of the Alberta Board report of December 1959, the cumulative ultimate adjusted reserves based on normal and low rates of appreciation are plotted as Figures B-6 and B-7. Best fit straight lines were drawn through the data points having a slope equivalent to a discovery rate of slightly less than 7.0 billion cubic feet per wildcat well. These lines were extrapolated to 7,000 wildcat wells. They then were arbitrarily reduced to give an ultimate reserve figure of some 86 to 88 trillion cubic feet by the time 20,000 wildcat wells (equivalent to one well for every ten square miles of potential gas area) are drilled.

The average number of exploratory wells drilled per year over the past seven and three-quarter years is 399. The Alberta Board assumed that exploratory drilling would continue normally at an average rate of 400 wells per year for the next ten years.

The Alberta Board prepared two year-by-year forecasts showing the anticipated reserve estimates for the ten-year period, 1960-1969 inclusive. The first was based on normal appreciation and normal exploratory drilling rate of 400 wildcat wells per year; the second, more conservative, was based on low appreciation and 300 wells per year. The Alberta Board felt that the latter forecast was a conservative

projection of the additional reserves that can be expected in the immediate future.

For the purpose of forecasting the cumulative initial disposable reserves for Alberta over the next thirty-year period, this Board has adopted the Alberta Board's statistical method assuming low appreciation and a drilling rate of 300 exploratory wells per year. The predicted cumulative initial reserves as of December 31, 1989 were 76.7 trillion cubic feet. The year-by-year forecast is shown in Figure 1. It should be noted that production to December 31, 1959 has been deducted. The ultimate reserves after allowing for production prior to 1960 are indicated to be 74 trillion cubic feet.

British Columbia: The use of the statistical approach at this time, in computing trends in growth and appreciation of reserves in British Columbia has limitations due to a lack of basic detail relating to accurate reserve estimates for previous years. Moreover, relatively few wells have been drilled to date in British Columbia as compared with Alberta. As development progresses and with the drilling of wildcat wells over a wider area, this method should reflect more accurately the potential ultimate reserves.

There has been considerable delay in development of pools in the area and in many instances there is just a single

well. Some pools of course are beyond economic reach at present. Difficulty of access to other pools permits winter work only. Westcoast announced through its counsel on the last day of hearings that the company had plans under way to construct pipe line facilities to connect the Clarke Lake and Petitot River fields. This should help provide the necessary incentive for more rapid development of known pools.

The Board, employing its established reserve figure of 2.2 trillion cubic feet, determined the arithmetic average of the discovery rate to be 8.8 billion cubic feet per wildcat well. It considers the Westcoast figure of 55 wildcat wells per year to be reasonable. At this rate the cumulative wells drilled by 1989 will be approximately 1,900. A projection of a plot of cumulative disposable reserves versus cumulative wildcat wells is shown in Figure 2. Basic data for the figure are shown on Table 5. This plot indicates that the cumulative initial disposable reserves of northeastern British Columbia will be 15.2 trillion cubic feet as of December 31, 1989, and, assuming a maximum density of one well per ten square miles, the ultimate cumulative disposable reserves will be in the order of 38.5 trillion cubic feet. This compares with the suggested reserves ranging from 60 to 75 trillion cubic feet estimated by CPA and others who used the geological or volumetric method.

Saskatchewan: Saskatchewan's remaining recoverable reserves as at December 31, 1958 have been estimated by the Saskatchewan Government to be 736 billion cubic feet and by CPA to be 1,159 billion cubic feet. This Board has accepted the Saskatchewan Government estimate and after considering evidence presented at the hearing has projected that figure to an estimated 2,900 billion cubic feet in 1989 (after deducting production to December 31, 1959). This is shown graphically in Figure 1.

Ontario: The Ontario Fuel Board estimated that initial disposable reserves of Ontario as of December 31, 1958 were 786 billion cubic feet. This Board adopted the estimated discovery rates presented in evidence by Trans-Canada. The reserves as of December 31, 1989 thereby become 1,026 billion cubic feet or 448 billion cubic feet after deducting production to December 31, 1959. (See Figure 1)

Finding on Trends in Discovery: Totalling the trend data for Alberta, British Columbia, Ontario and Saskatchewan results in a projection of the anticipated increase in initial disposable reserves of Canada (exclusive of Yukon and the Northwest Territories). This is shown as the uppermost curve in Figure 1. It indicates that the total initial disposable reserves for all four provinces will increase from approximately 30 trillion cubic feet as at December 31, 1959 to some 92 trillion cubic feet as at December 31, 1989.

SECTION 4

RESERVES, REQUIREMENTS AND SURPLUS

Alberta and Southern, Trans-Canada and Westcoast each presented evidence indicating how all or a portion of the Canadian long range requirements for natural gas could be met from present and future reserves of Canadian gas. The December 1959 Report of the Alberta Board also contains evidence to demonstrate that the Alberta reserves are sufficient to satisfy present and foreseeable requirements of that province together with the volumes authorized to be removed from the Province under Alberta permits, including gas to meet Canadian requirements, gas authorized to be exported to the United States and gas which the present applicants wish to export to the United States.

Method of Assessment

The total reserves of gas necessary for a market for a specific period may be separated into two portions, the actual volumes of gas delivered during that period, and the reserves necessary to ensure deliverability for the peak day requirement in the terminal year of the period. The former portion may be obtained by totalling the estimated annual requirements throughout the period. The latter portion may be obtained through the calculation of detailed deliverability schedules using the basic reserve-deliverability data

for each field. This is a time consuming process where a large number of markets are to be supplied from numerous fields. To simplify the procedure of estimating the reserves necessary to supply peak day requirements, the Alberta Board has developed a mathematical formula, adaptable to any selected period of requirements and desired degree of protection for those requirements. It has been used in this report to estimate three important factors:

(a) the reserves necessary to meet present and future Canadian requirements;

(b) the reserves necessary to meet the requirements of existing export licences;

(c) the reserves necessary to meet the present export applications.

The formula employs factors developed from a detailed examination of the reserve-deliverability characteristics of individual fields or groups of fields. For Alberta fields, the factors published in the December 1959 Report of the Alberta Board have been adopted. The factors for British Columbia fields were developed from the National Energy Board's study of available data concerning the characteristics of those fields.

Individual studies were not made of Saskatchewan and Ontario fields. They were assumed to have, on the average,

characteristics similar to those Alberta fields supplying Trans-Canada. In view of the relatively small reserves in these provinces, moderate departures from this assumption would have only a minute effect on the end results.

A summary of the formula, the derivation of which may be found in recent Alberta Board reports, is presented herewith.

The total reserves needed for future requirements for a period of n years, R_n, may be calculated as follows:

$$R_n = K \left(\sum_{1}^{n} A + 1.3\ FP_n \right)$$

The quantities needed for the calculation are:

- $\sum_{1}^{n} A$ = the cumulative annual requirements for n years in billions of cubic feet,
- n = the number of future years to be considered,
- P_n = the peak day requirement in the nth year, in MMcf,
- F = reserve-delivery ratio, i.e., ratio of reserves of gas in the reservoir (corrected to equivalent pipe line volumes) to their attributable deliverability, billion cubic feet per million cubic feet,
- K = reservoir recovery factor, i.e., ratio of disposable pipe line gas to the equivalent pipe line gas in the reservoir.

The formula in effect predicts, in terms of pipe line gas,

(a) the actual volumes of gas delivered to the pipe line over the period of the projection,

(b) the volume of pipe line gas required to be in place in the reservoir in the terminal year of the projection in order to supply peak day deliverability.

The Alberta Board has found that a correction factor of 1.3 has to be applied to the F values used for large composites of fields. This compensates for the amount by which the ratio of total reserves to total deliverabilities exceeds the sum of the individual ratios of the component fields. The same factor is used by this Board.

Using the formula method, the Board has ascertained the amounts of established reserves which it considers necessary to protect Canadian requirements for gas, plus gas committed under existing licences for export from Canada. It has also determined the additional volumes of future reserves which are necessary to provide fully for the estimated requirements of Canada for the next 30 years.

Table 6 tabulates by years for the period 1960 to 1989, the volumes of gas to be brought into and exported from British Columbia. These volumes are used to calculate the net gas requirements for that province. Columns 2, 3 and 4 of the table list the total requirements of British Columbia and are the same as those shown in Table 1. Columns 5, 6 and 7 indicate the anticipated and presently authorized exports of Westcoast at Sumas, Washington, to El Paso Natural Gas Company

(hereinafter called "El Paso") which has absorbed the original customer, Pacific Northwest Pipeline Company (hereinafter called "Pacific Northwest"). Columns 8, 9 and 10 indicate the volumes which may be removed from Alberta to British Columbia under the terms of the Alberta Government permit issued to Westcoast. The annual rates of removal shown in Column 8 have been arbitrarily reduced by this Board below the annual rates authorized in the permit, in order to provide uniform deliveries during the permit period. The volumes of gas to be delivered at Sumas as shown in Columns 5, 6 and 7 have been pro-rated to Alberta and British Columbia reserves as shown in Columns 11 to 16 inclusive. The allocation was made on the basis of an assumption that Alberta gas would be marketed in British Columbia and the United States in any year in proportion to the estimated total requirements of each market in that year.

Columns 17, 18 and 19 of Table 6 show the expected deliveries of gas to supply British Columbia from the Alberta Peace River area. These volumes were calculated by subtracting the quantities in Columns 8, 9 and 10 from those in 11, 12 and 13 respectively. Small volumes are currently being transported from Alberta to Dawson Creek, British Columbia by Peace River Transmission Company Ltd. (hereinafter called "Peace River Transmission") and have been added to the above differences. The requirements of the East Kootenay Area

(Table 2) which are expected to be supplied with gas from southwestern Alberta are indicated in Columns 20, 21 and 22. Columns 23, 24 and 25 show the net British Columbia requirements for British Columbia gas. Columns 26, 27 and 28 show the total of provincial plus authorized export requirements to be supplied from British Columbia.

Table 7 is a tabulation by years for the period 1960 to 1989 of requirements of Alberta and the net requirements for Canadian gas for the provinces Saskatchewan, Manitoba, Ontario and Quebec. Columns 2, 3 and 4 of this table indicate the Alberta requirements and agree with those shown in Table 1. Columns 5, 6 and 7 show the total requirements of Canada east of Alberta and have been obtained from the same table. The volumes of gas being imported into Ontario under the terms of a contract between Panhandle Eastern Pipe Line Company (hereinafter called "Panhandle Eastern") and Union Gas are shown in Columns 8 and 9. Tne amounts of peak day requirements which it is estimated will be met from storage developed in Ontario, peak shaving facilities or from line pack are shown in Column 10. The estimates were developed largely from information filed with the Royal Commission on Energy. Columns 11, 12 and 13 indicate the net requirements for Canadian gas east of Alberta while Columns 14, 15 and 16 show the corresponding requirements for Canadian gas east of British Columbia.

Table 8 is an illustrative allocation schedule indicating the manner in which the present and future needs of Canada and existing export licences can be met from established and future reserves. Column 1 of the table indicates the market area of Canada, the existing Alberta permit or the existing Canadian export licence to which the allocation has been made. Column 2 shows the period of the requirement. The period of the requirement for any export permit is the remainder of the authorized term of such export permit or licence. Two periods of requirements are shown for British Columbia, Alberta and the Canadian market east of Alberta namely, 1960 to 1980 and 1960 to 1989.

The 21 year period 1960 to 1980 has been selected as that for which requirements should be met from presently established reserves. In the case of Alberta, the estimated provincial requirements for the period are met completely from established reserves. This protection for Alberta consumers is a condition of the Government of Alberta before permitting removal of gas from the Province. The requirements elsewhere in Canada have been levelled at the 1963 rate for the balance of the 21 year period. According to evidence filed before the Board, in general it has not been practicable for pipe line companies to obtain contracts for the purchase or sale of gas for incremental requirements commencing more than three or four years in the future. Incremental requirements

beyond the 1963 level accordingly have been allocated to future discoveries of gas (future reserves). In every case, all requirements accruing after 1980 are assumed to be met from future reserves.

Column 3 of Table 8 indicates the total estimated deliveries of gas over the period. The corresponding peak day requirements in the terminal year are shown in Column 4. The data listed in Columns 3 and 4 for British Columbia requirements have been obtained from Columns 23 and 24 of Table 6. Those for Alberta have been obtained from Columns 2 and 3 of Table 7, while those for Saskatchewan, Manitoba, Ontario and Quebec are found in Columns 11 and 12 of that table. The data for the Alberta permits granted to Canadian-Montana, Peace River Transmission and Westcoast were obtained from Table D-2 of the December, 1959 Report of the Alberta Board but converted to 14.73 psia pressure base. The data shown for the existing Westcoast export licence are the estimates of deliveries of British Columbia gas at Sumas as shown in Columns 14 and 15 of Table 6.

Column 5 of Table 8 lists the reserve-delivery ratio, F, for the groups of fields expected to supply the various requirements. For Alberta fields, the ratios were obtained from Tables D-1, D-2 and D-3 of the Alberta Board's December 1959 Report. For British Columbia fields, the ratio

was calculated from basic data made available to this Board by the British Columbia Government and others. The reserves of pipe line gas in place necessary for terminal year peak day deliverabilities are shown in Column 6. Column 7, being the sum of Columns 3 and 6, lists the total reserves of pipe line gas in place required for each of the market areas. Column 8 gives the ratio, K, of disposable pipe line gas to pipe line gas in the reservoir. These data were developed in a manner similar to those of Column 5. The volumes shown in Column 9 of the table are the reserves of disposable pipe line gas necessary to meet the requirements for the periods shown in Column 2. These volumes have been segregated in Columns 10 and 11 into two categories; requirements to be supplied from established reserves, and those to be met from future reserves. The established reserves necessary for the protection of Canadian requirements for the period 1960 to 1980 inclusive, plus the two existing export licences total 21.0 trillion cubic feet. The additional reserves necessary to satisfy completely Canadian requirements for the period 1960 to 1989 are estimated to be 24.6 trillion cubic feet. The Board, having consideration for the trends, believes that these additional requirements can be met from reserves to be developed in the future.

Findings as to Surplus

Using the data which have been derived, it is now possible to relate the estimates of established and future reserves to the amounts of reserves necessary to meet requirements. Figure 3 is a graphical representation of the manner in which the present and future requirements for British Columbia gas compare with the present and future reserves of that province, by years, from 1960 to 1989 inclusive. Figure 4 is a similar illustration for the balance of Canada. The solid lines in each of the figures represent available reserves, established and future, while the broken lines represent reserves necessary to meet the requirements indicated.

Using the figures, a summary of the surplus of Canadian reserves over those necessary to meet Canadian requirements plus existing export commitments may be made as follows:

	Presently Established Reserves	Future Reserves Cumulative to 1980	Future Reserves Cumulative to 1989
	Trillions of Cubic Feet		
British Columbia			
Available reserves	2.2	11.3	15.0
Reserves necessary to meet requirements	3.1	5.4	7.2
Surplus	– (0.9)	5.9	7.8
East of British Columbia			
Available reserves	28.1	66.3	77.0
Reserves necessary to meet requirements	17.9	26.0	38.4
Surplus	10.2	40.3	38.6
Total Canada			
Available reserves	30.3	77.6	92.0
Reserves necessary to meet requirements	21.0	31.4	45.6
Surplus	9.3	46.2	46.4

The above summary indicates that after deducting from British Columbia's present reserves those allocated to the Westcoast (Sumas) licence and reserves necessary to meet the cumulative requirements of British Columbia from 1960 to 1980, estimated to 1963 and projected to the end of the 21 year period at that level, there is a deficiency in established reserves of 0.9 trillion cubic feet. On the other

hand the cumulative reserves based on future trends exceed cumulative requirements for complete protection of British Columbia and the Westcoast licence by 5.9 trillion cubic feet in 1980 and by 7.8 trillion cubic feet in 1989.

Established reserves are in excess of Canadian requirements east of British Columbia for 1960 to 1980 when estimated to 1963 and projected at that level to the end of the 21 year period, by some 10.2 trillion cubic feet. This surplus was determined after deducting gas allocated to the Canadian-Montana 1952 Alberta permit and transfers to British Columbia authorized by Alberta permits.

As shown, it is estimated that the cumulative reserves, based on future trends, will exceed cumulative requirements for complete protection of Canadian requirements east of British Columbia, and the previously mentioned permits, by 40.3 trillion cubic feet in 1980 and by 38.6 trillion cubic feet in 1989. Even if part of the surplus in established reserves east of British Columbia were used to offset the apparent deficiency within that province, there would remain a surplus of established Canadian gas reserves of 9.3 trillion cubic feet for use in considering the present export applications.

From the long-term point of view and having regard to the trends in discovery of gas, the estimated cumulative surpluses of future reserves of 46.2 trillion cubic feet to

1980 and the 46.4 trillion cubic feet to 1989 in excess of future Canadian requirements (including existing export licences for these periods) are very substantial.

Gas Requirements of the Applicants

The volumes of gas applied for by each of the applicant companies and the reserves necessary to supply the annual and peak day requirements as indicated in the applications are shown in Table 9. Column 1 lists the names of the applicant companies. Column 2 indicates the total volumes of gas for which application has been made. These volumes have been converted to a common heating value basis of 1,000 btus per cubic foot (Column 4). The terminal dates of the proposed permits are shown in Column 5. The terminal peak day requirement of each applicant is listed in Column 6. Column 7 shows the reserve-delivery ratio, F, considered to be representative of the combined sources of supply for each application. Column 8 indicates the formula calculation of the reserves of pipe line gas in place necessary to ensure the terminal peak day deliverability. The totals of pipe line gas in place necessary to meet the requirements of the applicants, shown in Column 9, have been converted through use of the ratio K, shown in Column 10, to the corresponding volumes of disposable gas, shown in Column 11. The total

reserves necessary to meet the combined requirements of the applicants are 8.3 trillion cubic feet. It is this figure which has to be compared with the 9.3 trillion cubic feet of established reserves which this Board has estimated to be surplus to Canadian requirement.

SECTION 5

TRANS-CANADA'S APPLICATION

Trans-Canada (a company having authority under a special Act of Parliament) is applying for

(a) a licence to export at a point on the international boundary near Emerson, Manitoba, 204,000,000 cubic feet per day, 74,000,000,000 cubic feet annually, and a total of 1,410,000,000,000 cubic feet over a period ending on the 14th day of May, 1981;

(b) a certificate of public convenience and necessity to construct and operate a 30-inch pipe line from a point on its existing line near Winnipeg to a point near Emerson, Manitoba, a distance of approximately 50.7 miles, together with additional compressor stations, meter stations and other works connected therewith to be installed on its existing pipe line and the proposed extension, to enable the company to transport the volumes of gas it is applying to export under (a) in addition to the gas it will supply to Canadian consumers;

(c) a licence to export near Niagara Falls, Ontario, such quantities of gas as Trans-Canada may have available on any day or days up to but not exceeding 204,000,000 cubic feet on any day over a period ending on the 14th day of May, 1981.

The company presently operates a long-distance gas transmission line from the Alberta boundary to the Island of Montreal, Quebec. It consists of 586 miles of 34-inch line from the Alberta-Saskatchewan boundary to Ile des Chenes near Winnipeg, 1,248 miles of 30-inch line from Ile des Chenes to Maple, north of Toronto, and 308 miles of 20-inch line from Maple to its terminus on the west end of Montreal Island. In addition, there are two branch lines — the first, 100 miles of 24-inch and 20-inch diameter from Maple to the Niagara River near Niagara Falls, and the second, 37 miles of $12\frac{3}{4}$-inch from Morrisburg to Ottawa.

A section of the 30-inch line running through northern Ontario — some 676 miles in length — is owned by the Northern Ontario Pipe Line Crown Corporation (hereinafter referred to as the "Crown Corporation") and the remainder is owned by Trans-Canada. Pursuant to agreements with the Government of Canada and the Crown Corporation, Trans-Canada pays a rental on the Crown Corporation's section of the line and has an option and an obligation to purchase it.

Canadian Sales

Trans-Canada has projected sales in its Canadian markets. These are discussed in section 2 of this report.

The company's general service sales contracts with

distributors are normally for a term of twenty years and conform with the rate schedules for the particular zone concerned. Industrial firm gas contracts are for a maximum period of ten years and off peak and winter peaking contracts are on a year-to-year basis. The rates for industrial and off peak gas fall within the maxima and minima established for each zone. Certain contracts give the distributor the right to an alternative contract on the same terms as may subsequently be granted to any other distributor in the zone, if the terms of such subsequent contract are considered to be more favourable. Special rates, which may vary between different distributors, are usually granted in respect of the first three years of the contract term which are looked on as a development period. There is also some variation in the terms and conditions under which revisions of the contracts may take place.

Northern Ontario Natural Gas Company Limited (hereinafter called "NONG") has substantial sales in both the 'Western' zone and in the 'Northern' zone. The withdrawal of that distributor as an intervenor in the hearing followed execution of a new contract for additional quantities of gas, with deliveries commencing November 1, 1961 at prices some 3¼ cents higher than the present rates for the respective zones. Trans-Canada also gave an undertaking

that, for a limited period, contracts with new large industrial users would be negotiated at prices based on the cost of the gas and its transmission to the point of delivery at the time of the negotiation of the contracts. NONG was assured of the opportunity to obtain gas on a "seller's option" basis comparable to that applying to Tennessee in respect of any export of gas at Niagara Falls and received an undertaking from Trans-Canada, for a limited period, to divert from one rate zone to another certain quantities of gas covered by existing contracts, at the same rates as those in effect for the zones in which the gas was delivered.

Trans-Canada also has an agreement to sell gas to the Canadian Western Natural Gas Company and Northwestern Utilities Limited (hereinafter called "the Alberta Utilities") should these companies be unable to purchase gas in Alberta on more advantageous terms than those set forth in the agreement.

The Alberta Utilities have entered into somewhat similar types of contracts with Alberta and Southern and Westcoast. The amount of gas which Trans-Canada may be called upon to supply is limited to a portion of the Alberta Utilities' requirements calculated on a pro rata basis with respect to the total volumes of gas which the three transmission companies are authorized to remove from Alberta.

Gas taken by the Alberta Utilities at a 70 per cent load factor or better is to be paid for at the weighted average price paid by Trans-Canada under gas purchase contracts dated after May 27, 1957, plus the Alberta Gas Trunk Line Company Limited (hereinafter called "Alberta Gas Trunk") transportation charge to be calculated as if the gas were delivered from the source or sources of supply nearest to the point at which the Alberta Utilities will take delivery. Additional or peak load gas is to be paid for at 1.3 times the aforesaid price.

There is also an arrangement between the Alberta Utilities and Trans-Canada whereby Trans-Canada will purchase gas from the Alberta Utilities surplus to their requirements.

Gas Supply

Trans-Canada adduced evidence showing that it had gas purchase contracts covering an estimated 7,692.9 billion cubic feet of gas at 14.73 psia, the equivalent of 7,977 billion cubic feet on a 1,000 btu basis. Under these contracts, Trans-Canada has the right to take up to a maximum of 991.7 million cubic feet daily.

The company also stated that there was a minimum of 600 billion cubic feet of reserves not under contract in fields from which it was purchasing gas. In most cases, the producers were anxious to sell this gas to Trans-Canada but

the company is unable to contract for the gas because its take-or-pay commitments under existing contracts are in excess of its contracted sales. The company pointed out that if its application to export gas at Emerson were not granted, it would be in the position of having to pay for some 71 million cubic feet of gas per day which it could not sell.

Trans-Canada presented a comprehensive and detailed reserve and deliverability study covering the majority of the fields from which it is purchasing gas and, in the remainder of the fields, it adopted the Alberta Board's figures.

Deliverable gas from its established reserves of 7,693 billion cubic feet through to October 31, 1980 was estimated by the company to be 6,514 billion cubic feet. This would provide for contracted and non-contracted but anticipated sales of some 6,769 billion cubic feet with no significant shortages in either peak day or annual volumes until 1976. The total estimated shortage is 255 billion cubic feet or 3.8 per cent.

The 6,769 billion cubic feet of estimated sales are made up of

(a) Canadian requirements estimated through 1962-63 and from then to October 31, 1980 at the 1962-63 level, totalling 5,176 billion cubic feet, includ-

ing 595 billion cubic feet of non-contracted but anticipated sales;

(b) a contracted export sale at Emerson of 1,509 billion cubic feet (including provision for compressor fuel, line loss, etc.);

(c) 84 billion cubic feet of gas to cover possible export sales to Niagara Gas and interruptible seller's option export sales to Tennessee Gas Transmission Company (hereinafter called "Tennessee") near Niagara Falls.

The Board considers Trans-Canada's estimates of reserves and deliverability to be reasonable. The shortages that will occur in the latter years are normal due to a decline in deliverability as fields become depleted and due to the pattern which is followed in making gas purchases. The Board believes that Canadian requirements are fully protected and that Trans-Canada will be able to purchase additional gas from the presently non-contracted reserves referred to and from new discoveries which should cover amply the estimated shortage of 255 billion cubic feet and the increments in demand after 1962-63.

Gas Purchase Contracts

Trans-Canada's gas purchase contracts fall into four basic categories which are designated by the initial

price to be paid for gas delivered at a point in a field subject to certain specifications and measured at a pressure base of 14.4 psia (prices shown in brackets represent the conversion to 14.73 psia);

(1) the 'ten-cent' contracts, executed prior to the end of May 1957, provide a price of 10.00 cents (10.23¢) per Mcf from the date of initial delivery through December 31, 1959, escalating one-quarter cent per year thereafter to a terminal price of 15.75 cents (16.11¢) in January 1982 and continuing at this price throughout the remainder of the term of the contract. The amount of gas purchased under the 'ten-cent' contracts represents 54.6 per cent of Trans-Canada's maximum day gas purchases in 1962-63;

(2) the 'twelve-cent' contracts, executed prior to the end of August 1957, provide for a price of 12.00 cents (12.27¢) per Mcf from the date of initial delivery through December 31, 1959, escalating one-quarter cent per year thereafter to a terminal price of 17.75 cents (18.16¢) in January 1982 and continuing at this price throughout the remainder of the term of the contract; the amount of gas purchased under the 'twelve-cent'

contracts represents 1 per cent of Trans-Canada's maximum day gas purchases in 1962-63;

(3) the 'thirteen-and-one-quarter-cent' contracts, executed during the period August 1957 to March 1959, provide for a price of 13.25 cents (13.55¢) per Mcf from the date of initial delivery through December 31, 1960, escalating one-quarter cent per year thereafter to a terminal price of 18.75 cents (19.18¢) in 1982 and continuing at this price throughout the remainder of the term of the contract; the amount of gas purchased under the 'thirteen-and-one-quarter-cent' contracts represents 27.5 per cent of Trans-Canada's maximum day gas purchases during 1962-63;

(4) the 'thirteen-and-one-half-cent' contracts, negotiated in May 1959, provide for an initial price of 13.50 cents (13.81¢) per Mcf through June 30, 1961, escalating in stages to a terminal price of 21.00 cents (21.48¢) in June 1983, which price continues for the balance of the term of the contract; under the 'thirteen-and-one-half-cent' contracts, Trans-Canada is obligated to take the gas only if it obtains authorization for export at Emerson; the amount of gas purchased under the 'thirteen-and-one-half-cent' contracts represents

7.9 per cent of Trans-Canada's maximum day purchases during 1962-63.

In addition to the aforementioned basic type contracts, special contracts were entered into with producers in the Westerose South (Dick Lake) field and have two price schedules. The first schedule, which is similar to that in the 'thirteen-and-one-quarter-cent' contract previously described, remains in force until six months after Alberta and Southern, which also has contracts to take gas from this field, has obtained all necessary authorizations to export to the United States a minimum of 200 million cubic feet and has commenced construction of the necessary transmission facilities, or until the day the actual export of a minimum of 200 million cubic feet per day is commenced, whichever is the sooner. Thereafter, the second price schedule comes into effect, which is similar to the schedule under the 'thirteen-and-one-half-cent' contract previously described. The amount of gas purchased in the Westerose South field represents 9 per cent of the maximum day gas purchases in the year 1962-63.

The 'ten-cent' and 'twelve-cent' contracts are for a term of twenty-five years from date of first delivery or expiration of Trans-Canada's Alberta permit, whichever first occurs. The 'thirteen-and-one-quarter-cent' and 'thirteen-and-one-half-cent' contracts have similar terms

except that the twenty-five years is from the date of contract.

Trans-Canada's basic contracts contain the following provisions for price increases:

(a) if the charge by Alberta Gas Trunk for gathering and transporting Trans-Canada's gas to its facilities at the Alberta-Saskatchewan boundary is less than four cents per Mcf, the price to the producer is increased by the difference between the four cents and the said charge;

(b) if Trans-Canada decreases the price of gas to its customers (distributors) who are purchasing more than 15 billion cubic feet per year, the price to the producer would be increased by 50 per cent of the reduction in price to the customer;

(c) commencing in 1968, the price payable to a producer is automatically increased to the weighted average price paid by Trans-Canada to all producers in the preceding year, if such weighted average price is more than that payable under a contract.

The contracts also contain provisions for renegotiation of price as follows:

(a) if earnings of Trans-Canada exceed 7½ per cent;

(b) commencing in 1968 and each five years thereafter;

(c) commencing in 1968, within sixty days from the date on which the overall volumes then authorized to be removed from Alberta are increased and Trans-Canada commences transporting same;

(d) commencing in 1968, within three months of the date that the overall volumes then being transported by Trans-Canada for its own account from western Canada through its pipe line system are increased.

In a few fields, Trans-Canada included in its purchase contracts a favoured nation type provision that if it entered into a contract at some later date with another producer in the same field at a higher price for gas, then the price payable under the previous contracts would automatically be raised to such higher price. Trans-Canada stated that nearly 100 per cent of the gas in the fields concerned was now under contract and this provision would have little effect.

The 'thirteen-and-one-half-cent' contracts negotiated by Trans-Canada with producers in the Westerose South (Dick Lake) field contain special renegotiation provisions which are different and more stringent than those in the other contracts. The Westerose South gas was originally contracted by Alberta and Southern and when an agreement was reached for Trans-Canada to take over a portion of the gas in the field from Alberta and Southern, the special renegotiation

provisions were inserted in the new contracts with Trans-Canada in lieu of the favoured nation clauses in the original Alberta and Southern contracts. The Westerose South gas under contract to Trans-Canada represents some 7 per cent of the company's reserves.

Authority to Remove Gas from Alberta

Trans-Canada has been granted the following permits from the Province of Alberta, authorizing removal of gas as follows:

Date	Permit No.	Max. Day Withdrawal	Max. Annual Withdrawal	Total Quantity authorized to be removed
		Millions of cubic feet at 14.4 psia		
14-5-54	TC 54-1 (as amended)	680	225,000	4,550,000
29-1-59	TC 59-2 (as amended)	270	90,000	1,700,000
13-1-60	TC 60-3	60	20,000	355,000
		1,010	335,000	6,605,000

These three permits expire May 14, 1981.

In addition to the foregoing amounts of gas, Trans-Canada has contracted to purchase from Saskatchewan Power up to 23 million cubic feet of gas per day for fifteen years, reducing to 11 million cubic feet in the twentieth year. This gas will be produced from the Medicine Hat field in Alberta and is covered by Alberta permit No. SPC 57-1 issued to

Saskatchewan Power, authorizing the removal of not more than 137.9 million cubic feet in any one day nor more than 45.3 billion cubic feet in any consecutive twelve-month period nor more than 620 billion cubic feet during the term of the permit, which expires on December 31st, 1984. Trans-Canada expects to take from Saskatchewan Power approximately 7.8 billion cubic feet per year for the first fifteen years, with decreasing amounts thereafter and a total quantity of 142 billion cubic feet over the contract period of twenty years. All the aforementioned quantities of gas are at a pressure of 14.4 psia and when converted to 14.73 psia result in Trans-Canada being authorized to take gas from Alberta (including the gas from Saskatchewan Power) to a total of not more than 1.01 billion cubic feet per day nor more than 335 billion cubic feet during any consecutive twelve-month period nor more than 6.596 trillion cubic feet during the period ending May 14, 1981.

Emerson Export

Proposed New Pipe Line Facilities: The application for a certificate of public convenience and necessity includes only facilities which the company proposes to construct in 1960. These include

(a) the 50.7-mile 30-inch export branch line from Ile

des Chenes to Emerson, which will connect with a 24-inch diameter line of the Midwestern Gas Transmission Company (hereinafter called "Midwestern") which proceeds some 504 miles south and east to Marshfield, Wisconsin; the 30-inch line is larger than is necessary to deliver the export volume currently applied for and the company, when questioned, acknowledged that this was the case but explained that the pipe was held in inventory, having been purchased several years ago in the United Kingdom;

(b) additional compressor facilities to provide for increasing loads in eastern Canada and more particularly to maintain pipe line pressure west of Winnipeg by reason of the proposed Emerson export, as follows:

(i) the addition of a 3,400 installed horse power compressor engine to an existing station, six new stations with a total of 50,610 horse power, all west of Winnipeg;

(ii) one additional 5,000 horse power station at Ramore, Ontario, and

(iii) on the Crown Corporation section, a 2,500 horse power addition to the

existing station at Port Arthur and one new 7,500 horse power station at Kenora, Ontario;

(c) a meter station at Emerson to measure the gas to be exported.

All construction is to be let by contract and if the 1960 construction program is commenced by May 1st, it is expected to be completed by October 15, 1960. The estimated cost of construction of facilities is as follows:

Trans-Canada	
Emerson pipe line - 50.7 miles 30-inch	$ 6,394,000
Emerson meter station	370,000
Main line compressor stations	25,453,000
Cathodic protection existing pipe line	119,000
Meter stations - new and modifications	281,000
Total - Trans-Canada	$32,617,000
Crown Corporation	
Compressor stations	$ 4,494,000
Cathodic protection	60,000
Total - Crown Corporation	$ 4,554,000
Total estimated cost of 1960 construction - Trans-Canada and Crown Corporation	$37,171,000

With respect to Canadian participation in the supply of materials, as mentioned previously the 30-inch pipe

is on hand. The company stated that pipe, sizes 16-inch and under, would be manufactured in Canada. Three compressor turbines would be constructed in Canada and three in the United States. With the exception of the turbines, 60 to 75 percent of the cost of compressor stations would be spent in Canada on items of Canadian origin. Virtually all the labour would be Canadian.

The Board is satisfied that the proposed facilities are adequate and necessary to enable the company to transport the volumes of gas required to supply the domestic and export markets and that the estimated cost of the proposed facilities is reasonable.

Export Markets: Trans-Canada has contracted for sales, or has reserved gas for sales to Canadian distributors, to a total of 235.4 billion cubic feet per year for 1962-63 and thereafter to 1980. It is applying for a licence to export up to 74 billion cubic feet per year.

Trans-Canada received its first permit to remove gas from Alberta in May 1954. This permit was apparently intended to cover the requirements of Canadian markets eastward as far as Montreal, and also to provide some gas for export. The proposed arrangements for export at Emerson reflected in the present application, commenced with a precedent agreement dated August 11, 1955, between Trans-Canada and Tennessee. This agreement, subsequently assigned

to Midwestern, a wholly-owned subsidiary of Tennessee, has been amended several times. This precedent agreement provides that a contract in a certain form will be entered into by the parties when all necessary governmental authorizations are obtained.

The essential elements of the proposed contract may be summarized as follows. Daily delivery is to be a maximum of 204 million cubic feet at 14.73 psia and 60° F (200 million cubic feet at 15.025 psia in the contract as drafted). The take-or-pay load factor is to be 75 per cent in the first three years, and 95 per cent thereafter. Although the contract is for 25 years, Trans-Canada's application is for the period ending on the 14th day of May, 1981. This coincides with the terminal date set forth in the permits issued to Trans-Canada by the Alberta Board.

In the precedent agreement, Tennessee undertakes to sign a contract to accept gas at Trans-Canada's option at a point near Niagara Falls, in quantities up to 204 million cubic feet per day, but this undertaking is contingent upon and coextensive with the proposed export at Emerson. The proposed Niagara transaction is, in effect, a separate matter in these proceedings, and is discussed at a later point.

Gas exported at Emerson would be paid for under a two-part rate, in which the demand charge escalates every

five years while the commodity charge remains constant at 20.75 cents per Mcf. The resultant average prices were put in evidence as follows:

Period	Demand Charge	Load Factor	AVERAGE PRICE 15.025 psia cents per Mcf	AVERAGE PRICE Converted to 14.73 psia cents per Mcf
	$	%		
1st 3 years	2.30	75	30.83	30.23
next 2 years	2.30	95	28.71	28.15
2nd 5 years	2.60	95	29.75	29.16
3rd 5 years	2.91	95	30.82	30.22
4th 5 years	3.21	95	31.86	31.23
5th 5 years	3.52	95	32.93	32.29
20-year average			30.60	30.00
25-year average			31.07	30.46

Gross income from the export sale over the 20-year term of the proposed licence would be in the order of $425 millions.

Midwestern, Trans-Canada's customer, presented evidence that its proposed purchase contract with Trans-Canada is matched by markets in Minnesota and Wisconsin adequate to absorb the gas.

The Federal Power Commission of the United States has, after exhaustive investigation, found in its Opinion 331 of October 31, 1959 that the "construction and operation of

the facilities proposed by Midwestern and Michigan Wisconsin (its principal customer), and the sales of natural gas by them, ... are required by the public convenience and necessity, and certificates therefor should be issued ...". The Commission has issued such certificates, subject to certain conditions not here relevant, and has authorized Midwestern to import a maximum of 200 million cubic feet per day (15.025 psia) at Emerson.

The adequacy of the markets proposed to be served by Midwestern with Canadian gas is demonstrated to the satisfaction of this Board by the findings and actions of the Federal Power Commission as set forth in Opinion 331. It is supported in these proceedings by the evidence of Mr. Freeman, President of Midwestern.

Border Price: The Board is required to satisfy itself that the proposed export price is just and reasonable in relation to the public interest. One test that may be applied is for the Board to be satisfied that the export price is fair in relation to the prices charged to Canadian distributors in the area adjacent to the point of export, with due allowance being made for variations in the terms and conditions of sale.

Trans-Canada's customers in the Manitoba rate zone, namely, Greater Winnipeg Gas Company, Plains-Western Gas & Electric Co. Ltd., and Inter-City Gas Limited, have 20-year

contracts, under the rate schedule for that zone, to purchase gas from Trans-Canada at prices fixed without escalation (except for certain contingent tax increases) over the life of the contracts. As indicated above, the average export price over 20 years at Emerson would be 30 cents per Mcf (95 per cent load factor after the third year), as compared with a price of 24.94 cents per Mcf, which is available under the Manitoba zone rate schedule at a 90 per cent load factor. Even if the cost of transportation between Winnipeg and Emerson (say 0.9 cents, on the basis of 1.72 cents per Mcf per 100 miles, the average cost adduced in evidence by Trans-Canada) is deducted from the Emerson price, the comparison remains favourable. Two of the three contracts for firm gas that Trans-Canada has with customers in the Manitoba rate zone are at a 50 per cent load factor, and accordingly the average price actually to be paid thereunder for general service after a three-year development period is 34.99 cents. The third Manitoba contract is under the Small General Service provisions of the schedule, which has no load factor requirement but a fixed price of 38.0 cents after the three-year development period. The fact that these prices are higher than the average prices to be charged at Emerson does not alter the fact that the distributors in Manitoba could, if they saw fit to do so, buy gas under the existing Manitoba zone rate schedule at a

90 per cent load factor and acquire it at a lower price than that to be paid at Emerson on a 95 per cent load factor. Exact comparison is not possible since the Manitoba zone rate schedule does not contain a provision for a 95 per cent load factor but some allowance for load factor is proper, fair and necessary in any comparison of average gas prices. The Board is, therefore, satisfied that the proposed Emerson price is adequate in relation to the prices at which Trans-Canada is selling gas in the Manitoba rate zone.

Trans-Canada presented evidence from which it was possible to compare the cost of service arising from the proposed Emerson export with the average cost of service for its Canadian markets, and also evidence comparing the rate of return anticipated from the Emerson export and the rate of return expected from its Canadian sales. This evidence indicates that the rate of return on the Emerson sale would be substantially higher than on the Canadian sales. Notwithstanding certain qualifications which might be applied to this comparison, the Board finds that the proposed Emerson sale would enhance the average rate of return on the sales of the system.

There are no major natural gas pipe lines in the area immediately south of the international boundary at Emerson so that it is not possible to compare the border

price with prices charged for United States gas. Evidence before the Board indicated that in the general area in which the gas exported at Emerson would be sold, the delivered cost of the Canadian gas is greater than that of gas now being received from other sources.

The Board accordingly finds that on the basis of the various tests applied, the proposed Emerson export price is just and reasonable in relation to the public interest.

Financing of New Construction: The additional facilities required for the proposed export at Emerson would represent the major portion of the company's 1960 construction program amounting to $37,171,000. Of this amount, $4,554,000 is payable by the Crown Corporation in respect of work on that Corporation's section of the line.

To meet capital expenditures during the next three years, including $133,834,000 for the purchase of the Crown Corporation section in November 1961, Trans-Canada expects to require additional financing to the extent of $233,000,000. The 1960 capital expenditures would be financed partly through the issue of bonds and increased bank loans, but in the following two years Trans-Canada expects to obtain $120,000,000 from the sale of bonds, $65,000,000 from debentures and $45,000,000 from the issue of common stock. The feasibility of the company's financing

plan was testified to by its officials and by representatives of investment banking houses. Witnesses affirmed that full opportunity would be afforded to Canadians to participate in the financing, in a manner similar to that in which its public financing to date has been carried out. The company's equity is at present held preponderantly in Canada.

Without sales of gas at Emerson Trans-Canada's financing position would be materially prejudiced, according to the company's evidence. In particular, it was stated that the purchase of the Crown section would be delayed for some years because of inability to effect the necessary financing by reason of the low rate of return to be expected from the remainder of Trans-Canada's operations. This would prejudice the company's position and make additional financing more expensive and difficult.

Niagara Falls Export

The export of gas near Niagara Falls would require no new construction, since the line built to import gas from Tennessee during the period of building up the Toronto area market from 1954 to 1958 prior to delivery of Alberta gas would be used for this purpose. Because of available pressure in Trans-Canada's main line, no additional compression would be necessary in order to accomplish the export.

Market to be Served: Trans-Canada's precedent agreement with Tennessee, dated August 11, 1955, included an undertaking by Tennessee to accept gas at a point near Niagara Falls in quantities up to 204 million cubic feet a day wholly at Trans-Canada's option. This undertaking is contingent upon and coextensive with the proposed export at Emerson. The Emerson portion of the agreement was subsequently assigned to Midwestern, but any export at Niagara Falls would still be made to Tennessee.

Tennessee could undertake to accept such volumes of seller's option gas only because it has storage capacity available, into which any Canadian gas (or American gas displaced by it) could be injected. The market to be served cannot, therefore, be identified by locality, since the gas would simply become part of the total gas supply available to Tennessee for its customers anywhere in the northeastern United States.

Trans-Canada stated that its intention was to export at Niagara only such surplus quantities of gas as it had in its system after satisfying the entire requirement of its Canadian market. The company's estimates of gas supply and requirements show very little gas as being available for such export but it was represented that "the availability of this sale will enable the applicant to maintain and/or improve the load factor on its pipe line notwithstanding a drop in

the requirements of its Canadian market on any day or days".

Trans-Canada suggested to the Board that this interconnection with Tennessee would be of great assistance to Canada in the event of an emergency. Such an emergency did occur about a year ago and gas from Tennessee was made available to Trans-Canada. With most of the gas customers in central Canada dependent on a single pipe line 1,300 to 2,000 miles long, this temporary alternative source of gas could be of substantial importance.

Tennessee has filed an application with the Federal Power Commission for authority to import gas under this agreement. Since the agreement is contingent upon export at Emerson, it may be assumed that the Federal Power Commission will hear that application only if and when a Canadian export licence is issued to Trans-Canada in respect of the Emerson export.

The Board is satisfied that, subject to the approval of the import application by the Federal Power Commission, the market to be served would be adequate and secure.

Border Price: The price to be paid by Tennessee for any gas delivered near Niagara Falls is 37 cents Canadian per Mcf at 15.025 psia. This is equivalent to 36.27 cents at 14.73 psia. Because of the unusual nature of the sale, it is difficult to compare this price with prices to Canadian customers of Trans-Canada, and because of the manner in which

any gas exported would be merged into Tennessee's general gas supply, it is difficult to gauge whether the price represents fair valuation of the gas in the export market.

Under its January 1960 agreement with NONG, Trans-Canada has confirmed that "if granted permission to export gas on a seller's option basis at Niagara, (it) will be offering to each of its distributor customers gas on a seller's option basis similar to that offered to Tennessee under the proposed contract to export at the Niagara Falls delivery point. It is recognized by this company that the price of such offering will be related to the distance such gas is transmitted to the distributor in question, having regard to the price per Mcf of gas paid by Tennessee for similar service at Niagara Falls." This spells out the policy Trans-Canada had previously stated in general terms, namely, that it would export at Niagara only gas it could not sell in Canada. Nothing in its agreement obligates NONG to take any such interruptible gas.

The most nearly comparable sales contracts to which Trans-Canada is a party, both geographically and in terms of price, are those with Ontario Natural Gas Storage and Pipelines Limited (hereinafter called "Ontario Natural"). The main contract, which allows wide leeway to Trans-Canada in scheduling deliveries, but does include delivery requirements, calls for payment at the rate of 39 cents per Mcf.

This is a low price in relation to Trans-Canada's other major sales contracts; the reason is the degree of flexibility in accepting deliveries which Ontario Natural can tolerate because of its storage facilities, its owned production, and its other supply arrangements. Another contract with Ontario Natural does concern a service which is described as "on a wholly interruptible basis and ... subject to curtailment or interruption in Trans-Canada's sole discretion"; however, the nature of the service contemplated is the provision, so far as Trans-Canada has interruptible gas available, of up to 1,800 Mcf per day in the periods June 21 to October 31, 1959, and April 1 to October 31 in 1960 and 1961. This service is stated to be intended to provide interruptible service through United Gas Limited to Steel Company of Canada Limited. The price in this contract is 33½ cents per Mcf.

From the foregoing it is clear that Trans-Canada has established its willingness to sell in Canada any interruptible gas it may have, and that it has contracted to sell certain interruptible gas, at a point of sale fairly close to the existing connection near Niagara Falls, at a price of 33.5 cents per Mcf, as compared with the proposed export price of 36.27 cents.

After due consideration of the various factors, both tangible and intangible, relating to the proposed export

near Niagara Falls, the Board finds that the proposed price at the boundary is fair and reasonable in relation to the public interest.

SECTION 6

ALBERTA AND SOUTHERN'S APPLICATION

Alberta and Southern is applying for a licence to export gas from Canada at a rate not exceeding 458,750,000 cubic feet in any one day nor more than 153,270,000,000 cubic feet in any consectutive twelve-month period nor more than 3,826,000,000,000 cubic feet during the term of the licence applied for, which is for a period of twenty-five years calculated from the commencement of the effective date of export of gas under the said licence.

The applicant company is incorporated under the laws of the Province of Alberta and is a wholly-owned subsidiary of the Pacific Gas and Electric Company (hereinafter called "Pacific Gas and Electric"). The principal function of Alberta and Southern is to purchase gas in Alberta for export to the marketing areas in California served by Pacific Gas and Electric. The applicant also has a contract to sell gas to Canadian-Montana, which is currently applying for a licence to export such gas to the marketing area in Montana of The Montana Power Company (hereinafter called "Montana Power").

Canadian Sales

Alberta and Southern has entered into a contract to sell gas to the Alberta Utilities upon the same general basis as the Trans-Canada contract to which previous reference has been made. Alberta and Southern is to make gas available to the Alberta Utilities after maximum use has been made of their other sources of supply. Gas supplied to the Alberta Utilities at not less than a 70 per cent load factor is to be purchased at a price equal to the weighted average price paid by Alberta and Southern in Alberta in the month such gas is delivered, plus the Alberta Gas Trunk transportation charge to be calculated as if the gas were delivered from the source or sources of supply nearest to the point at which the Alberta Utilities will take delivery. Additional or peak load gas is to be paid for at 1.3 times the aforesaid price.

Gas Supply

Alberta and Southern presented evidence to the Board that it had proved and probable reserves under contracts, letter agreements, and options totalling some 4,824 billion cubic feet and that a further 283 billion cubic feet was non-contracted but available to the company from fields in which it had negotiated gas purchase contracts or options.

Gas purchase contracts are for a term of twenty-five years from the month of July next following the date of first delivery or until the expiration of the authorization to remove gas from Alberta, whichever occurs first.

The price schedules are uniform in all contracts for gas delivered to a point in the field, subject to certain specifications and measured at a pressure base of 14.4 psia. The initial price is 13.5 cents per Mcf (13.8¢ at 14.73 psia) for gas delivered prior to July 1, 1961. On July 1, 1961, it increases to 14.5 cents (14.8¢) and increases annually to 17.25 cents (17.6¢) per Mcf in 1968 and thereafter at five-year intervals to 21 cents (21.5¢) in 1983.

Provision is made in the contracts for price renegotiation or redetermination by arbitration at five-year intervals commencing in 1968.

Contracts also contain a provision whereby the price to the seller is increased, starting in 1968, to the weighted average price paid by Alberta and Southern to all producers for dry gas in Alberta during the preceding contract year if such weighted average price is higher than that payable under a contract.

If, at any time during the life of a contract, any new or increased occupation, production, severance, or sales tax is imposed on the producer, Alberta and Southern is required to reimburse the producer for one-half of such new or increased taxes.

All contracts have a favoured nation commitment whereby Alberta and Southern undertakes with the producer that if it enters into subsequent contracts prior to 1968 for purchase of gas under similar conditions, the company must send copies of the new contracts to the producer and if he considers the form of the new contract more beneficial, he has a period of days in which to request a substitute contract in the new form.

The options which Alberta and Southern has obtained, give the company the right, for specified periods of time, to purchase gas developed within specific areas covered by the options under the terms of the standard contract previously described. Mr. Smith, giving evidence on behalf of Alberta and Southern, expressed the opinion that the form of the options would tend to stabilize prices as they gave the company the first right of refusal on large amounts of future reserves for which all the conditions of sale are agreed upon in advance.

The Board and its staff estimate the established reserves of the fields in which Alberta and Southern was purchasing gas under contract, letter agreement, or option to be some 4,179 billion cubic feet (4,221 billion cubic feet - 1,000 btu equivalent), of which some 200 billion cubic feet are available to but not contracted to Alberta and Southern. It is estimated that of the established reserves, some 3,183 billion cubic feet will be produced during the first twenty years to meet the export requirements of Alberta and Southern and Canadian-Montana of 3,283 billion cubic feet, with annual and peak day shortages of 100 billion cubic feet in the nineteenth and twentieth years. To meet the 25-year requirements of 4,100 billion cubic feet, the Board estimates that the company would require another 670 billion cubic feet of gas.

The Board has not accepted all the probable reserves estimated by Mr. Wege but is of the opinion that reserves to offset the 670 billion shortage would in all probability be available from the fields in which the company has gas under contract or option and also has the necessary authorization under Alberta permits to remove the gas.

<u>Authority to Remove Gas from Alberta</u>

Alberta and Southern has been granted two permits by the Alberta Board authorizing the removal of gas as follows:

Date	Permit No.	Max. Day Withdrawal	Max. Annual Withdrawal	Total Quantity authorized to be removed
		millions of cubic feet at 14.4 psia		
7-4-59	AS 59-1 (as amended)	450	151,200	3,780,000
13-1-60	AS 60-2	50	16,800	420,000
		500	168,000	4,200,000

Both permits are for a term of twenty-five years from the date of the first removal of gas from Alberta pursuant to the permit or to October 31, 1986, whichever is the sooner.

When converted to a pressure base of 14.73 psia, the permits authorize the removal of not more than 489 million cubic feet in any one day nor more than 164.2 billion cubic feet during any consecutive 12-month period nor more than 4.1 trillion cubic feet during the life of the permit.

The gas which Alberta and Southern is authorized to remove from Alberta includes the amount of gas which the company has contracted to sell to Canadian-Montana for export to the United States and which is the subject of a separate application by Canadian-Montana. This latter contract calls for the delivery of not more than 32.6 million cubic feet in any one day nor more than 10.95 billion cubic feet in any one year nor more than 273.75 billion cubic feet during the term of the contract, which is effective as long as the Alberta and Southern project to sell gas from Canada to Pacific Gas Transmission Company (hereinafter called "Pacific Gas Transmission") in the United States is operative.

Pipe Line Facilities

The company does not own nor does it propose to own any pipe line facilities. It proposes to use facilities to be constructed by Alberta Gas Trunk, to take gas from field gathering points in Alberta for delivery to Alberta Natural at a point in Section 17, Township 8, Range 5 west of the fifth meridian adjacent to the Alberta-British Columbia boundary for gas going to California, and for delivery to Canadian-Montana at a point near Cardston adjacent to the Alberta-Montana boundary for gas going to Montana.

Alberta Natural is currently applying to build a 36-inch line to transport gas on behalf of Alberta and Southern and Westcoast through British Columbia from the terminus of Alberta Gas Trunk line at the Alberta-British Columbia boundary to connect with a line to be constructed in the United States by Pacific Gas Transmission from a point adjacent to the British Columbia-Idaho boundary near Kingsgate. Pacific Gas Transmission proposes to build 614 miles of 36-inch line from the international boundary near Kingsgate, B.C. to the California-Oregon boundary near Malin, Oregon, where it will connect with the facilities of Pacific Gas and Electric.

Export Market

Alberta and Southern has entered into a sales contract dated December 15, 1958 with Pacific Gas Transmission. This company which is effectively controlled by Pacific Gas and Electric, has agreed to enter into a contract with Pacific Gas and Electric, under which it would deliver Canadian gas to a point of interconnection with its facilities on the Oregon-California boundary.

The contract between Alberta and Southern and Pacific Gas Transmission calls for average daily delivery of 418 million cubic feet, maximum daily delivery of

456 million cubic feet, and a 90 per cent annual take-or-pay load factor. These volume figures are on a pressure base of 14.73 psia. The contract would run "for as long as The Project is able to operate in such manner as to accomplish its principal purpose". The term requested for the export licences is twenty-five years. The term set forth in the permit issued to Alberta and Southern by the Alberta Board is to end "twenty-five years from the date of the first removal of the gas from the Province...or October 31, 1986, whichever is sooner".

Gas exported by Alberta and Southern would be paid for, not on a fixed price basis, but on a cost of service basis. The cost of service would be composed of (a) the average field cost per thousand cubic feet to Alberta and Southern, (b) an allocation per thousand cubic feet of Alberta and Southern's operating expenses, depreciation, amortization, taxes and return on investment at 7½ per cent annually, (c) Alberta Gas Trunk's transport charge to Alberta and Southern in respect of gas delivered to Alberta Natural on behalf of Alberta and Southern, and (d) Alberta Natural's transport charge to Alberta and Southern. The applicant estimates that the sum of these costs of service in each of the first five years of operation would be as follows:

Year of Operation	Average Cost of Service (Cents Canadian per Mcf) (14.73 psia)
1	25.11
2	26.03
3	26.64
4	27.08
5	27.38

Aside from the escalation in field prices which Alberta and Southern has contracted to pay, there are a number of possible variations in the future cost of service which make it impracticable to give a precise estimate of gross income from the export sale over the term of the requested export licence. In the fifth year the annual cost of service measured at the point of export would exceed $41 millions.

The market to be served by the gas proposed to be exported by Alberta and Southern is wholly within that part of California, which is served by Pacific Gas and Electric. That company is established and responsible, and evidence indicates that demand for gas in its market area has increased rapidly and is continuing to do so. The Canadian gas here under discussion would constitute about 22 per cent of its estimated purchases in 1962; the evidence before the Board is that Canadian gas is and will be increasingly important in meeting the growing demand on Pacific Gas and Electric.

The Federal Power Commission has before it an application, by Pacific Gas Transmission, which is the counterpart of Alberta and Southern's application herein. The State of California has supported the application of Pacific Gas Transmission before that Commission. No intervention in opposition was entered by any party. The record in the case (Dockets G-17350, G-17351, G-17352) has been completed before a Presiding Examiner, whose decision is now awaited.

The Board is satisfied that the export market to be served is adequate and would be secure if the Federal Power Commission were to see fit to approve Pacific Gas Transmission's application.

Border Price

In the absence of sales in Canada, or in areas of the United States close to the point of export, of such a nature that a comparison of prices can usefully be made, determination of the appropriateness of the border price must be tested primarily on the basis of the cost of service proposed to be charged by Alberta and Southern to Pacific Gas Transmission.

There appears to be reasonable assurance that in the Canadian portion of the project all costs will be recovered, including full depreciation, during the term of the licence applied for, plus a rate of return of

$7\frac{1}{2}$ per cent. Alberta and Southern has contracted to pay for gas in the field under gas purchase contracts which have been approved by Alberta, the province of origin, and to which this Board finds no reason to object. Under the terms of sales contracts, either executed or proposed, which have been filed with the Board, Alberta and Southern is to be reimbursed by Pacific Gas Transmission for the cost of the gas and its transmission to the international boundary via Alberta Gas Trunk and Alberta Natural. Although the individual items comprised in the cost of transmission as placed in evidence before this Board are designated by reference to the Federal Power Commission Uniform System of Accounts, all relevant charges appear to be accounted for. No serious difficulty is anticipated as a result of possible divergencies in a future Canadian accounting classification.

The applicant's proposal contemplates that all gas to be exported would be transmitted directly to California. The Board is satisfied on the evidence before it that Pacific Gas and Electric's estimates of the delivered cost of Canadian gas at Antioch would represent adequate valuation of that gas under present circumstances.

After due consideration of the various factors, the Board finds that the proposed export price is just and reasonable in relation to the public interest.

Financing of Project

The project, exclusive of construction by Alberta Gas Trunk, is expected to require financing equivalent to $253,539,000 (U.S.) divided as follows:

Alberta and Southern	$ 1,838,000
Alberta Natural	37,611,000
Pacific Gas Transmission	132,276,000
Pacific Gas and Electric	81,814,000
	$253,539,000

Alberta and Southern is and will remain a wholly-owned subsidiary of Pacific Gas and Electric. Authorized capital is to consist of 100,000 common shares at $10 par value. It is estimated that at the commencement of operations 10,000 shares will have been issued providing capital of $100,000. The remainder of the funds required by the company will be received from Pacific Gas and Electric in the form of advances against notes issued by Alberta and Southern.

Alberta Natural expects to have 930,000 shares of common stock outstanding prior to commencement of operations, one-third owned by Pacific Gas Transmission, one-third by Westcoast and the remaining one-third by the public. These shares are to have a par value of $10 each which will also be the issue price to Pacific Gas Transmission and to Westcoast. The shares offered to the

public will be issued at $10.50 each, the additional 50 cents per share being the amount which it is estimated will be required to cover the costs of sale and issuance of the shares, including underwriters' fees. The public offering will be under the direction of two Canadian investment houses and the Canadian public will have a right of first refusal for these shares. Additional funds, as required, will be raised from the sale of mortgage bonds. These will be sold through a group of Canadian underwriters and Canadian institutional investors will be given an opportunity to purchase the bonds to the extent that a Canadian demand for such bonds exists.

Pacific Gas Transmission expects that it will be required to issue securities to a total of $132,276,000 including the funds necessary for investment in Alberta Natural. The initial financing will be through the issue of common stock and at the commencement of operations it is estimated that 2,210,000 shares will be outstanding, of which 50 per cent will be owned by Pacific Gas and Electric, 25 per cent in varying amounts by Canadian Bechtel Limited, Blyth and Co., Inc., International Utilities Corporation and Montana Power. The remaining 25 per cent will be offered for public sale and it is proposed to offer the shares first in Canada for a reasonable period and only the unsold balance, if any, will then

be offered in the United States. It is proposed that the shares will be offered to the public at $9.50 per share compared with $9.00 per share payable by the original sponsors, the difference of 50 cents per share being the amount considered necessary to cover the costs of issuance and sale to the public. Concurrently with the sale of the common stock, convertible debentures will be sold. Common shareholders will have a pre-emptive right to purchase these debentures and it is anticipated that the original sponsors will purchase 75 per cent of the face value of the debentures so that the distribution will generally conform with that of the common shares. The debentures sold to the public will be at a premium sufficient to cover costs of sale and issuance and it is anticipated that at the commencement of operation $13,300,000 of the debentures will have been issued. Thereafter, it is intended to issue mortgage bonds to a total of $98,810,000 and assurance has been given that Canadian institutional investors will have an opportunity to purchase the bonds to the extent that a Canadian demand for such bonds exists.

In so far as Pacific Gas and Electric's investment in the project is concerned, it is contemplated that the funds required, including those necessary for the acquisition of Pacific Gas Transmission securities and the financing of Alberta and Southern will be obtained

in the same way as those for other expansion of the company's facilities, maintaining the approximate ratios of 50 per cent bonds, 16 per cent preferred stock and 34 per cent common equity. Pacific Gas and Electric is a public company whose securities are widely held.

Financial witnesses testified that in their view the different parts of the project could be financed in the manner indicated above. It may be noted that, although there is no opportunity for Canadians to participate in Alberta and Southern since it is and will be a wholly-owned subsidiary of Pacific Gas and Electric, Alberta and Southern is not directly concerned in the construction or operation of pipe line facilities. The company was formed for the purpose of purchasing gas from producers, paying the Canadian pipe line companies for transmission of the gas to the international boundary on a cost of service basis, and recovering these costs, together with a return on the relatively small amount of the company's investment in plant, from the purchaser of the gas at the international boundary. Canadian investors will be given an opportunity to acquire a very substantial interest not only in the Canadian portion of the project through purchase of Alberta Natural securities but in the much larger United States portion of the project through purchase of securities of Pacific Gas Transmission.

SECTION 7

ALBERTA NATURAL'S APPLICATION

Alberta Natural (a company having authority under a special Act of Parliament) is applying for a certificate of public convenience and necessity to construct and operate a 36-inch gas transmission line, the said pipe line to follow a route commencing at its junction with the pipe line of Alberta Gas Trunk at a location in Section 17, Township 8, Range 5 west of the fifth meridian near the Alberta-British Columbia boundary thence generally in a south-westerly direction through British Columbia, terminating at the point of junction with a pipe line to be constructed, owned, and operated by Pacific Gas Transmission on the international boundary between the Province of British Columbia and the State of Idaho in the vicinity of Kingsgate, a total distance of approximately 108 miles.

The Crow's Nest Pass Coal Company Limited filed an intervention objecting to the proposed route of Alberta Natural's pipe line through its coal fields. After consultation between counsel and agreement by the parties concerned, an alternative route suitable to all concerned was selected.

Alberta Natural proposes to transport the gas to be exported by Alberta and Southern and Westcoast.

Proposed New Facilities

The design of the 36-inch line, with wall thick-

nesses of .406 and .438 inches, will permit maximum design pressures of 844 and 911 psia. It is proposed to construct, at the present time, one compressor station having an installed horsepower of 14,000. This will permit the delivery to Pacific Gas Transmission of 452 million cubic feet per day for the account of Alberta and Southern and 152 million cubic feet per day for the account of Westcoast. The Alberta and Southern gas will be purchased at the boundary by Pacific Gas Transmission, who will in turn transport it to California for resale to Pacific Gas and Electric. The Westcoast gas delivered to the international boundary will be purchased by El Paso and transported by Pacific Gas Transmission for delivery to the El Paso system at a point near Spokane, Washington.

The 36-inch diameter lines of Alberta Natural and Pacific Gas Transmission, with the installation of additional compressor capacity, would be capable of transporting 800 million to a billion cubic feet per day. The lines are over-designed for the presently proposed throughput.

A meter station will be constructed by Alberta Natural at a point in Canada near Kingsgate, to measure the gas to be exported.

The construction of the Alberta Natural project will be done under contract and it is expected that it will

be completed by November 1961, provided all necessary authorizations are obtained promptly. The company stated, through a witness, that it was its intention to buy as much as possible of the pipe, equipment and other materials in Canada. In his closing argument, counsel, on behalf of this applicant, gave an undertaking that maximum use of Canadian labour would be made in the construction of the line.

Cost of Construction

The estimated capital cost of the Alberta Natural project is:

Direct Costs	Total	Per Inch-Mile
Main line transmission (incl. rights-of-way)	$24,625,000	$6,514
Compressor Station (incl. land)	5,246,000	1,388
Measurement and regulation (incl. land)	780,000	206
	$30,651,000	$8,108
Indirect Costs		
Engineering, inspection, contingencies	3,064,000	811
Interest during construction (6 per cent - construction period 22 months)	2,005,000	531
Miscellaneous (incl. working capital and intangible plant)	651,000	172
	$36,371,000	$9,622

A witness for the applicant explained that the apparent high cost of construction as related to cost per inch-mile was due to the rugged nature of the terrain through which the line will pass.

Pacific Gas Transmission is a company incorporated under the laws of the State of California. The estimated cost of its projected 614 miles of 36-inch line, including three compressor stations with 27,500 installed horsepower, is $128,900,000.

Financing of the Alberta Natural and the Pacific Gas Transmission lines has been discussed in Section 6 of this report in the Board's review of the proposed financing of the Alberta and Southern project.

SECTION 8

WESTCOAST'S APPLICATION

Westcoast (a company having authority under a special Act of Parliament) is applying for a licence to export gas from Canada at a point on the international boundary near Kingsgate at a rate of not more than 165 million cubic feet in any one day nor more than 54 billion cubic feet in any one year and a total volume of 1 trillion 100 billion cubic feet over a period of not less than twenty years commencing January 1st following the date of first export of gas from Canada or February 29, 1984, whichever is the sooner.

Canadian Sales

Westcoast has contracted to sell to the Canadian Western Natural Gas Company of Calgary up to 50 million cubic feet of gas per day from the Calgary field, providing that on or before the 15th day of January each year Canadian Western serves Westcoast with written notice setting forth the daily volumes, if any, which Canadian Western desires to take during the twelve-month period commencing on the 1st day of November next following the giving of such notice. Canadian Western is to pay for the gas a price per thousand cubic feet equivalent to that paid by Westcoast at the exit of the Jefferson Lake Petrochemicals of Canada Ltd. (hereinafter called "Jefferson Lake") processing plant in the Calgary field, plus any cost of transportation if

Canadian Western does not take delivery of the gas at the exit of the plant.

Westcoast also proposes to make gas available to communities in the East Kootenay area of British Columbia (see Table 2 for market estimate). Westcoast filed a letter from Inland (a certified public utility under the Gas Utilities Act of the Province of British Columbia) dated July 29, 1957, wherein this latter company stated that it is prepared to make an application for a certificate of public convenience and necessity to serve the communities in the aforesaid area within economic reach of the Alberta Natural line which will transport gas for Westcoast.

Gas Supply

Westcoast has contracts with producers in the Calgary and Savanna Creek fields. The company estimates the pipe line gas available under contract for export to be 1,371 billion cubic feet measured at 14.73 psia and on a 1,000 btu basis.

Savanna Creek Field

A contract was negotiated by Westcoast with all the producers in the field who have unitized their interests, to purchase an average of one million cubic feet per day of pipe line gas for every 10 billion cubic feet of recoverable reserves of pipe line gas up to a total of 100 million

cubic feet per day. The contract also provides, subject to certain conditions, for the purchase of additional gas in the same ratio to reserves up to 50 million cubic feet per day. Westcoast will arrange to take delivery of the raw gas at the wellhead, gather, dehydrate, and transport it to a plant at Coleman for removal of hydrogen sulphide and other impurities. The hydrogen sulphide will then be processed by Jefferson Lake for the recovery of sulphur.

Westcoast will pay the producer for the dry pipe line gas recovered from the processed raw gas according to a pricing schedule. Under the schedule, Westcoast will pay for gas delivered prior to January 1, 1963, 12 cents per Mcf measured at 15.025 psia (11.8 cents at 14.73 psia); thereafter the price increases one-third cent per year for the term of the contract, which expires on January 1, 1982. The schedule also provides for the following increases to the original prices referred to:

(a) a one-cent increase if the production during any month equals 150 million cubic feet per day or if in any month the total volume of gas received by Westcoast for export from an area within fifty miles of the Savanna Creek field or within an area of the Province of Alberta bounded on the north by the north line of Township 26, on the east by the east line of Range 22 west of the fourth

meridian, and on the west by the west line of range 8 west of the fifth meridian (both areas are hereinafter called "the area") equals 250 million cubic feet per day but is less than 350 million cubic feet per day;

(b) a two-cent increase if, during any month, the production from the field equals 150 million cubic feet per day and if during the same month the average daily volume of gas received by Westcoast for export from sources within the area equals 300 million cubic feet per day but is less than 400 million cubic feet per day, or if in any month during which the average daily volume of gas received by Westcoast for export from sources within the area equals 350 million cubic feet per day but is less than 400 million cubic feet per day;

(c) a three-cent increase if, during any month, the average daily volumes of gas which Westcoast receives for export from sources within the area equal 400 million cubic feet per day or greater.

The contract also provides for further price increases: in the event that

(a) buyer shall voluntarily grant either directly or indirectly a reduction in price to Pacific Northwest (now El Paso), such reduction shall automatically increase the price to be paid to producers by an equal amount per Mcf, to be effective at the same time as the reduction to Pacific Northwest becomes effective;

(b) Pacific Northwest shall grant Westcoast an increase in the resale price, Westcoast will increase the price to the producers by 50 per cent of the amount of such increase per Mcf.

There is a further provision that in the event Westcoast shall enter into any contracts for the purchase of gas with any producer in Western Canada upon terms more favourable to such producer or producers than the terms of the Savanna Creek contracts with producers, the Savanna Creek producers shall have the right to have their contracts modified so as to make applicable to the sale and purchase of gas such more favourable terms as are contained in the said contracts.

Calgary Field

Westcoast has a contract with Jefferson Lake and Mobil of Canada Limited who control some 70 per cent of the reserves in the Calgary field. The term of the contract is for twenty years from date of first delivery of gas.

The interest of Mobil is a reversionary one by reason of a farm-out agreement with Jefferson Lake. Under the farm-out agreement, Jefferson Lake undertakes to develop the gas, to install field gathering lines, to erect a gas processing plant and an attendant sulphur manufacturing plant for the purpose of processing the gas by extraction of hydrogen sulphide and other products therefrom and making available for market, merchantable pipe line gas. Jefferson Lake further represents it proposes to purchase gas at the wellhead from other producers and to make such gas available to Westcoast after processing.

Westcoast is committed to take 100 million cubic feet of gas per day and an additional 1 million cubic feet per day for each 8 billion cubic feet of recoverable pipe line reserves in excess of 800 billion cubic feet of original recoverable pipe line reserves up to and including 1,200 billion cubic feet of such reserves.

The price to be paid by Westcoast at the exit of the Jefferson Lake processing plant is 14 cents per Mcf at a pressure of 14.4 psia (14.3¢ at 14.73 psia) for gas delivered prior to January 1, 1962. The price then increases to 14.5 cents (14.8¢) for 1962, 15 cents (15.3¢) for 1963 and thereafter escalates one-quarter cent each year for the remainder of the term of the contract.

Renegotiation of price, by arbitration if necessary, is provided for on July 1, 1970 and at the end of each succeeding five years.

A favoured nations clause provides that the seller is entitled to adopt any contract entered into by Westcoast for the purchase of the gas in the Province of Alberta in an area which lies south of the northern boundary of Township 60.

The Board estimates the reserves of Westcoast under contract in the two fields to be some 1,350 billion cubic feet and the total established reserves in the two fields from which Westcoast is purchasing gas to be some 1,765 billion cubic feet.

The Board believes, after taking into consideration Jefferson Lake's undertaking to purchase at the wellhead from other producers in the Calgary field and the Alberta Board's allocation of gas to the City of

Calgary from the Calgary field, that Westcoast can deliver for export at Kingsgate not more than, in any one day, 152 million cubic feet, nor more than 51 billion in any consecutive twelve-month period nor more than 1,020 billion during the term of the export licence applied for, after making provision for a supply of gas to the East Kootenay district of British Columbia.

Authority to Remove Gas from Alberta

Westcoast has been granted permit WC 59-3 by the Alberta Board, authorizing the removal of gas on a 14.73 psia pressure base as follows: not more than 161.3 million cubic feet in any one day nor more than 52.8 billion cubic feet in any consecutive twelve-month period nor more than 1,075 trillion cubic feet during the term of the permit, which is twenty years from date of first removal of gas pursuant to the permit or February 29, 1984, whichever is the sooner.

Proposed New Facilities

The applicant proposes to construct only a gathering system in the Savanna Creek field and a purification and dehydration plant at Coleman, Alberta.

The gas to be exported by Westcoast will be transported in Alberta through the facilities of the Foothills Division of Alberta Gas Trunk to connect with

the proposed Alberta Natural pipe line at a point in Section 17, Township 8, Range 5 west of the fifth meridian near the Alberta-British Columbia boundary, with the possible exception of the sour gas lateral line from the Savanna Creek field to the Coleman purification plant. If Alberta Gas Trunk does not wish to proceed with the construction of the said sour gas line, it is to be built by a wholly-owned subsidiary of Westcoast.

Alberta Natural will deliver the gas from the terminus of Alberta Gas Trunk to the facilities of Pacific Gas Transmission at a point on the international boundary near Kingsgate.

The cost of the facilities to be installed by Westcoast is estimated to be:

Savanna Creek Gathering System	$1,093,000
Purification and Dehydration Plant at Coleman	6,918,000
Total	$8,011,000

The sum of $4,864,000, representing the cost of the lateral line from Savanna Creek to Coleman, including metering facilities, is included in the estimate of capital cost for the Foothills Division of Alberta Gas Trunk, which is dealt with separately.

<u>Export Markets</u>

Westcoast's proposal for export is based upon a contract agreement with El Paso (formerly Pacific Northwest), originally entered into May 25, 1957, and subsequently amended from time to time. The term of the contract is to be for twenty years from the January 1st following the first delivery of gas, and from year to year thereafter until terminated on due notice by either party. The agreement, as amended, calls for a contract volume of 150 million cubic feet per day at 14.9 psia (151.731 million cubic feet at 14.73 psia) to be delivered at not less than a 90 per cent annual load factor, at a price commencing at 25 cents and escalated over the term of the contract to 30 cents but not in any event to be less than the cost of service incurred in purchasing, processing and transmitting the gas to Kingsgate, including an annual rate of return of 7½ per cent on the net investment in facilities required for delivery. The cost of service includes the charges which Westcoast would be required to pay to both Alberta Gas Trunk and to Alberta Natural for transporting Westcoast's gas through their respective systems.

The applicant estimates that the cost of service for gas delivered to El Paso at the boundary will average 26.16 cents Canadian over the first five years, and over the twenty year term of the contract a minimum of 28 cents.

As in the case of Alberta and Southern, the number of variables which may affect the cost of service in ways presently unpredictable make it impossible to calculate precisely the gross income from the export sale over the term of the export licence requested.

The gas proposed to be exported by Westcoast at Kingsgate would be blended with the total supply of El Paso and would reach different areas at different times in a given year. Under average day conditions, Canadian gas, including that supplied under Westcoast's existing export licence at Sumas together with the proposed Kingsgate export, would directly supply all of El Paso's customers in Washington, Oregon and Idaho. On peak days, gas would have to be moved north from Wyoming to serve southern Idaho and parts of Oregon and Washington. By displacing United States gas in this Northwest Division, the Canadian gas would assist materially in making feasible the proposal of El Paso in association with the Colorado Interstate Gas Company to install a new 34-inch pipe line (the Rock Springs project) to provide gas to southern California at a border connection near Las Vegas. The witness Mr. Hunsaker, Chief Pipe Line Engineer of El Paso, stated in evidence that the Kingsgate gas "is absolutely necessary to us". Since El Paso's peak day requirements on its entire system in 1959-60 are 4.45 billion cubic feet, and are expected to rise to 5.45 billion cubic feet

by 1964-65, there appears to be no doubt as to the ability of the El Paso system to absorb the additional Canadian gas.

The Federal Power Commission has before it an application in the name of Pacific Northwest (now El Paso) in Dockets G-17902 and G-18033 for authority to import the Kingsgate gas and to build and operate certain facilities required for its transmission. No material intervention in opposition to the application arose during the hearings. These have been completed, and the recommended decision of the Presiding Examiner is presently awaited. The Colorado Interstate Rock Springs project has not yet been the subject of hearings before the Federal Power Commission.

The Board is satisfied that the export market to be served is adequate, even without the Rock Springs project, and would be secure if the Federal Power Commission were to see fit to approve the Pacific Northwest-El Paso application in respect of Canadian gas proposed to be purchased at Kingsgate.

Border Price

As in the case of Alberta and Southern, there are no sales contracted for in Canada with which to compare prices which will be paid for the proposed export gas at load centres close to the international boundary. Again, it is difficult, if not impossible, to compare the price of Canadian gas in the United States markets to be served with the prices of gas coming into the same markets from United States sources. The immediately preceding section outlined the wide range of the market which the gas proposed to be exported by Westcoast at Kingsgate would serve. This gas would be blended with gas exported through Sumas and would serve proportions of the Pacific Northwestern States which would vary as load conditions vary, and also would make possible additional service to southern California.

The test of the adequacy of border price which is practicable is the cost of service proposed to be charged by Westcoast to El Paso. Estimates were placed in evidence by the applicant as to the cost of gas at Kingsgate in the first five years of service, as follows:

Year of Operation	Average Cost Cents per Mcf
1	25.66
2	25.86
3	26.15
4	26.51
5	26.63

Westcoast expects to receive, on the average, somewhat less per Mcf at the border than Alberta and Southern. The difference is small and could be due to a number of causes, including the shorter average haul for Westcoast gas.

The comments made herein on the cost of service aspects of the Alberta and Southern project apply equally, in the view of this Board, to the Westcoast project.

After due consideration of the various factors, the Board finds that the proposed Kingsgate export price is just and reasonable in relation to the public interest.

The Board has before it at this time, in so far as exports by Westcoast are concerned, only the proposed export at Kingsgate. The existing export licence held by Westcoast, under which gas is being exported at Sumas, British Columbia, is not before the Board in these proceedings.

Financing of New Construction

The construction for which Westcoast will be directly responsible is confined almost entirely to the purification and dehydration plant at Coleman, and the Savanna Creek gathering system, which together are estimated to cost somewhat more than $8,000,000. In addition, Westcoast will require $3,100,000 in respect of investment it proposes to make in Alberta Natural.

A financial witness stated that he saw no problem in arranging for provision of the funds required by Westcoast. This opinion was based on the supposition that Westcoast's construction would total $12,875,000, including the estimated cost of constructing 43 miles of pipe line from the Savanna Creek field to the main Alberta Gas Trunk facilities. Alberta Gas Trunk may undertake this construction on its own account. On the other hand no explanation was made of how the company proposed financing the $3,100,000 required for investment in Alberta Natural. Furthermore, as no specific financing plan had been formulated no assurance could be given on the matter of Canadian participation in the financing, although it was stated that, as of January 1, 1960, over 60 per cent of the company's outstanding shares were owned in Canada. If the export application of Westcoast were to be approved, such approval should be conditioned upon Westcoast filing with the Board prior to commencement of construction a plan of financing satisfactory to the Board.

The construction necessary in the United States to make this Canadian gas available to the El Paso system consists mainly of 17 miles of 30-inch pipe line linking the Pacific Gas Transmission line with the existing El Paso facilities in the vicinity of Spokane, Washington. This would involve about $2.4 millions which it may be assumed could be readily covered as part of El Paso's normal financing.

SECTION 9

CANADIAN-MONTANA'S APPLICATION

Canadian-Montana (a company having authority under a special Act of Parliament) is applying for

(a) a certificate of public convenience and necessity to construct and operate a 16-inch line approximately 3 miles in length from a point on the Canadian-United States border in Township 1, Range 24 west of the 4th Meridian in the Province of Alberta, to a point in Township 1, Range 24 west of the 4th Meridian in the Province of Alberta, at which point it will be connected to a pipe line to be built by Alberta Gas Trunk;

(b) a licence to export gas from Canada in a total amount of 273,750,000,000 cubic feet, at a maximum daily rate of 36,000,000 cubic feet and not to exceed 10,950,000,000 cubic feet in any consecutive 12-month period, for a period of 25 years from the date of the first delivery under such licence.

Canadian Sales

There are no Canadian communities which could be served by the applicant's proposed line.

Gas Supply

Canadian-Montana has negotiated a contract with Alberta and Southern to purchase 30 million cubic feet per day with a maximum daily demand of 32.6 million cubic feet and an annual take-or-pay provision based on 90 per cent of the average daily volume. Both the average daily and the maximum daily amounts may be increased by agreement between the parties. Canadian-Montana, in its application for a licence, asked for authority to export a maximum of 36 million cubic feet daily in order to give flexibility, although the annual amounts and total quantity of gas applied for correspond with a take of 30 million cubic feet per day.

The price which Canadian-Montana will pay for gas is based on cost of service, including the average field cost of gas to Alberta and Southern, the transportation charge of Alberta Gas Trunk, and all other costs incurred by Alberta and Southern in making the sale to Canadian-Montana at the junction of its line and that of Alberta Gas Trunk near the international boundary.

Authority to Remove Gas from Alberta

The gas which Canadian-Montana proposes to

purchase from Alberta and Southern for export is covered by permits AS 59-1, as amended, and AS 60-2 issued to the latter company by the Alberta Board.

Pipe Line Facilities

The three miles of pipe line, certification of which is applied for, will deliver the gas to be exported from its connection with the Alberta Gas Trunk line in southern Alberta to a line to be built by Montana Power from a point on the Alberta-Montana boundary southeast of Cardston, Alberta, to Cutbank, Montana, a distance of 51 miles.

The proposed line is 16-inch, wall thickness .250 of an inch, with a design pressure of 945 psia. No compression is necessary. Due to proximity to the international boundary, gas will be measured at the metering station of Alberta Gas Trunk at its point of connection with the applicant's line.

It is proposed to have the applicant's line built by the same contractor who builds the 42-mile branch line for Alberta Gas Trunk from its main line. Provided all necessary authorizations are received shortly, the line is scheduled to be in operation by November 1961.

The estimated cost of construction is as follows:

	Total	Per-Inch-Mile
Survey, right-of-way, damages	$ 6,180	$ 129
Materials	110,820	2,309
Installation	56,883	1,185
Escalation, contingencies, interest during construction	30,969	645
	$204,852	$4,268

Export Markets

The gas proposed to be exported would be sold at the international boundary to Montana Power, to provide part of its general gas supply for service within the parts of Montana served or proposed to be served by that company. The gas service of Montana Power was originally commenced in 1931 on the basis of gas production in Montana. This production has proven inadequate to supply the growing requirements of the system. Since 1952 Montana Power has been importing gas from the southeastern part of Alberta, under an export licence separate from the present application, and involving reserves and facilities some distance further east than those here involved. The company is also purchasing gas from Montana-Dakota Utilities Company, under a contract which is due to expire on December 31, 1964. The record indicates that Montana Power has little

hope of improving its gas supply from Montana production or from other United States sources, and must seek Canadian gas to continue to meet both its present requirements and load growth.

Because of the interrelation of this project with those of Alberta and Southern and Westcoast, the Federal Power Commission consolidated the import application of Montana Power with those of Pacific Northwest (now El Paso) and Pacific Gas Transmission. The record in the proceedings concerning Montana Power has been completed without the appearance of any interventions in opposition, and the recommended decision of the Presiding Examiner is now awaited.

Provided that the Federal Power Commission sees fit to approve Montana Power's application, the market to be served by the proposed export would in the view of the Board be adequate and secure. This Board notes the extent to which this market is becoming increasingly dependent on Canadian gas.

Border Price

As in the cases of Westcoast and Alberta and Southern, there is no sale in a contiguous area of Canada by which the adequacy of the border price can be tested. As in those other cases, the border price is to be

established on the basis of cost of service. Cost of service in the case of Canadian-Montana will include Alberta and Southern's cost of acquiring the gas and transporting it through the facilities of Alberta Gas Trunk to a point on that company's line near the international boundary, the price being Alberta and Southern's cost of service to that delivery point. Canadian-Montana will sell to Montana Power at the international boundary at this cost plus all operating and maintenance expenses incurred in connection with receipt and delivery of the gas, fixed charges, taxes and a 7½ per cent return. The applicant estimates its selling price at the border, as follows:

Year of Operation	Average Cost Cents Canadian per Mcf
1	22.63
3	24.16
5	24.96

The calculation of this cost of service appears to be reasonable in the circumstances.

The applicant stated in evidence that this border price could properly be compared with the cost of gas presently being purchased from Montana-Dakota Utilities Company, which is 15.69 cents (U.S.) per Mcf at the Wyoming-Montana boundary. It was also stated

in evidence that the Canadian gas to be taken under the proposed contract would be the most expensive gas ever purchased by Montana Power, and that a substantial increase in that company's gas rates would be necessary to compensate for the higher cost of the Canadian gas.

After due consideration of the various factors, the Board finds that the proposed export price is just and reasonable in relation to the public interest.

Financing of Project

Since Canadian-Montana will be required to construct only three miles of connecting pipe line, without the need for any compression, between the facilities of Alberta Gas Trunk and those of Montana Power, the capital cost to Canadian-Montana is estimated at only $204,852 and the necessary funds will be obtained by Montana Power on a loan basis. Estimated cost of constructing Montana Power's section of the pipe line in Montana is $2,573,000 (U.S.); this amount would represent only about 25 per cent of normal construction financed by Montana Power in each of the past eight or ten years. In view of the evidence as to financial rating of Montana Power securities in the United States, financing for the project should present no difficulty. Montana Power securities are widely held and the fact

that Canadians are not in this case offered an opportunity of more direct participation in the relatively minor financing of the Canadian-Montana line does not appear to be of consequence.

SECTION 10

NIAGARA GAS' APPLICATION

Niagara Gas (a company having authority under a special Act of Parliament) is applying for:

(a) A certificate of public convenience and necessity under Part III of the Act to construct and operate a 12-inch diameter pipe line approximately 8½ miles in length connecting with the pipe line of Trans-Canada at a point in Stormont County in the Province of Ontario and running to a point on the international boundary near the municipality of Cornwall in the Province of Ontario at which point it will be connected with a pipe line to be built by St. Lawrence Gas Company, Inc., (hereinafter called "St. Lawrence").

(b) A licence under Part VI of the Act to export to St. Lawrence at a point on the international boundary near Cornwall, Ontario, 16,710,000 cubic feet of gas per day; 3,765,700,000 cubic feet of gas annually and a total quantity of 73,521,750,000 cubic feet of gas during the period ending June 30, 1980.

Canadian Sales

The applicant does not propose to sell any gas in Canada. Its line passes through an area now served by Lakeland Natural Gas Limited.

Gas Supply

Niagara Gas and Trans-Canada entered into an agreement on May 27, 1959, which provides that upon the fulfilling of certain conditions, namely, the obtaining of necessary authorizations, both in Canada and the United States, Trans-Canada and Niagara Gas will enter into a contract for the purchase of gas from Trans-Canada by Niagara Gas, such gas to be resold at the international boundary to St. Lawrence.

Trans-Canada has indicated that, while under the terms of the agreement it is not required to dedicate gas reserves to the performance of the proposed purchase contract prior to its execution, 73.521 billion cubic feet of gas which Niagara Gas has applied to export during the period ending June 30, 1980 would be available from its non-contracted supplies of gas.

Pipe Line Facilities

The application for a certificate of public convenience and necessity to construct this export pipe line is for a 12-inch pipe line extending approximately 8.8

miles from Trans-Canada's main line northwest of Cornwall, in Lot 20, Concession 6, Cornwall Township, Stormont County, Ontario, to a point on the international boundary, being midway across the new high level bridge spanning the channel of the St. Lawrence River to the south of Cornwall Island.

Niagara Gas has obtained, in addition to other right-of-way and crossing approvals:

(1) the consent of the St. Lawrence Seaway Authority to occupy Cornwall Canal lands and to cross the Cornwall Canal;

(2) the consent of the Cornwall International Bridge Company to cross the north channel on the existing Roosevelt Bridge and the south channel of the new south channel high level bridge. (No evidence was presented to show approval of the right to cross the proposed north channel high level bridge yet to be built);

(3) permission of the Department of Public Works of Canada to cross the St. Lawrence River, a navigable water;

(4) approval of the St. Lawrence Seaway Development Corporation and the United States Corps of Engineers for the design of the pipe line installation on the new south channel high level bridge.

The proposed Niagara Gas pipe line would connect with a line of similar size 15.9 miles in length in the State of New York owned by St. Lawrence. No compression facilities would be required. Since no sale of gas in Canada is proposed from this export line, measurement of export quantities would be at the Trans-Canada take-off meter installation. St. Lawrence will also meter the gas flow in a station near Massena, New York.

All construction is to be done under contract. Evidence was given that if all necessary authorizations were obtained shortly, construction would begin approximately April 1, 1960 and be completed within approximately 90 days.

The estimated capital cost of the proposed pipe line as submitted is:

Materials other than bridge crossings	$ 204,704
Installation other than bridge crossings	105,956
Bridge and canal crossings, materials and labour	74,680
Regulating and odorizing station at connection with Trans-Canada	25,000
North channel bridge crossing	37,940
	$ 448,280
Estimated cost per inch-mile for 8.8 miles of $12\frac{3}{4}$-inch O.D. pipe	$ 4,000

The Board is satisfied that the proposed facilities are adequate to transport the volumes of gas which Niagara Gas has applied to export and that under the circumstances the estimated cost of the proposed facilities is reasonable.

Export Market

Niagara Gas, a wholly-owned subsidiary of The Consumers' Gas Company (hereinafter called "Consumers' ") proposes to purchase gas from Trans-Canada near Cornwall, Ontario, to transport it to the international boundary for sale to St. Lawrence, another wholly-owned subsidiary of Consumers', for distribution in certain parts of upper New York State not presently served with natural gas.

This gas would be distributed by St. Lawrence through a pipe line system to be constructed from the area of Massena on the east, to Ogdensburg on the west, and providing service also to such communities as Norfolk, Norwood, Potsdam, Canton, Madrid and Waddington. Detailed estimates of anticipated markets according to location, class of service and class of customer were presented by expert witnesses. This Board is satisfied that in general the area under discussion could be expected to absorb the quantities of gas at the prices which were given in the evidence.

St. Lawrence has made application to the New York Public Service Commission and to the Federal Power Commission. Before both regulatory bodies St. Lawrence was opposed and a competitive application put forward by Niagara Mohawk Power Corporation (hereinafter called "Mohawk Power") and New York State Natural Gas Corporation (hereinafter called "New York Natural"). The New York Public Service Commission reserved its decision, pending a decision of the case before the Federal Power Commission; the New York Public Service Commission did not intervene in the latter proceeding, in which the record has now been completed and the recommended decision of the Presiding Examiner is awaited. If the Federal Power Commission were to see fit to approve the application of St. Lawrence both the adequacy and security of the market proposed to be served by the Niagara Gas export could be considered to have been definitely established.

Mohawk Power and New York Natural intervened in the hearing before this Board to oppose the granting of an export licence to Niagara Gas. They expressed an interest in obtaining at some future time some quantity of seller's option interruptible gas from Trans-Canada, and to illustrate the seriousness of their intentions adduced evidence that Mohawk Power had installed in the Iroquois Dam, being part of the works associated with the St. Lawrence Seaway, lines

of pipe intended to form part of the Canadian side of an international pipe line connection. This installation was made without approval by the public agencies either of Canada or of Ontario charged with regulation of construction of pipe lines under the respective jurisdictions.

Counsel for these intervenors pointed out that, if the application were approved, Canada would be the sole source of supply for St. Lawrence. The service area of St. Lawrence, if its plans and those of Niagara Gas received all necessary Canadian and United States authorizations, would become dependent on Canadian gas, so that interruption of service at the end of the term of an export licence would tend to create hardship and also friction between the respective national governments. It was argued that since the requirements were projected at only the 1963 level for the balance of the licence period, they must be expected to grow; therefore it must be expected that granting of this initial application would be followed by applications for additional quantities of gas. Since the export would be a firm demand at a high (90 per cent) load factor, to be delivered near the end of the Trans-Canada system, it might be difficult to provide fully for the peak demands of Canadian customers as well as this export at periods in Trans-Canada's development when its then existing capacity is fully utilized.

Border Price

The agreement between Niagara Gas and St. Lawrence for the export of gas at a point on the international boundary near Cornwall, Ontario, provides that the price of the gas to St. Lawrence shall be the cost of the gas to Niagara Gas under that company's contract with Trans-Canada with an additional charge to compensate for its transmission to the international boundary.

The Niagara Gas agreement with Trans-Canada establishes the price for contracted demand gas on the basis of a two part rate, in which the demand charge increases after eight years, again after twelve, and finally after sixteen years, while the commodity charge is 31 cents per Mcf for the first four years and 32 cents for the remaining sixteen years of the contract. The average prices resulting from applying this two part rate under the 90 per cent load factor to be contracted for may be compared in a general way with the average general service prices available under Trans-Canada's Eastern Zone rate schedule, under which gas is supplied to Lakeland Natural Gas Limited, distributors for an area including Cornwall, and to Quebec Natural Gas Corporation, distributors for the Montreal area. The comparison, which is subject to numerous qualifications and therefore cannot be regarded as precise, is as follows:

Average Price at 90 Per Cent Load Factor
Trans-Canada

	Niagara Gas Contract Mcf	Eastern Zone Rate Mcf
	cents	cents
1st four years	54.38	46.45
2nd four years	55.38	46.45
3rd four years	56.48	46.45
4th four years	57.39	46.45
5th four years	58.49	46.45
20-year average	56.42	46.45

The Board considers the price to be paid by Niagara Gas is fair and reasonable in relation to the prices at which gas is available to Trans-Canada's Canadian customers in the Eastern Zone.

The additional charge to be paid by St. Lawrence to Niagara Gas for transmitting the gas to the international boundary is set in terms of fixed annual sums in the first ten years, and on a cost of service to be computed for the remaining ten years of the contract. The total for the first ten years would be $387,500 as follows:

	Annual Charge
First 18 months	$ 14,000
Next year	29,000
Next 7½ years	45,000

With a depreciation rate of 1.5 per cent per annum, the total cost of operation and maintenance, taxes and depreciation and a rate of return of 7 per cent would vary considerably depending on the amount of capital cost allowance taken for income tax purposes. If maximum capital cost allowance were claimed, the estimated costs would total $458,000 during the first ten years which would exceed the recoveries provided for in the contract by a considerable margin, due largely to the lower annual charges made during the first two and one-half years. If, on the other hand, capital cost allowance were claimed to the extent only of the amounts charged as depreciation, the estimated costs for the first ten years would be $603,000 so that the recovery provided for in the contract would fall short of meeting these costs.

The depreciation rate of 1.5 per cent per annum used in these calculations is in accordance with the normal practice of Consumers'; it was stated by an official of that company that this rate had been arrived at on the basis of the company's estimate of the realistic life of the installation. The rate proposed for depreciating the facilities of St. Lawrence is also 1.5 per cent per annum.

Mr. Jones, Vice-President of Consumers' and Niagara Gas, stated that the possibility of an undepreciated investment in the export facilities of Niagara Gas having to be written off if a renewal of the export licence were not granted on its expiry was a calculated business risk, but not, in his opinion, a serious one.

If a depreciation rate of 5 per cent commensurate with a 20-year licence were used, and the same amounts as were charged for depreciation were claimed for capital cost allowance purposes, the total for the first ten years of operation would be about $634,000. It has been stated on behalf of the company that alternative policies in respect of capital cost allowance would make little difference to the total taxes payable during the first ten years. Once again, the amount receivable under the contract with St. Lawrence would fall far short of reimbursing Niagara Gas for these costs.

Over the 20-year period the rate of depreciation charged would have relatively little effect on total costs since increased charges for depreciation would to a considerable extent be offset by a lower return. The terms of the contract should ensure full recovery of Niagara Gas transmission costs during the second ten years but during the first ten years, regardless of the capital cost allowance policy followed for income tax purposes, a 5 per cent depreciation rate would appear to result in Niagara Gas

failing to be reimbursed for the company's transmission costs during that period by a considerable margin. Although the Board is satisfied that the price to be paid to Trans-Canada is just and reasonable, the Board is not satisfied with the proposed arrangements between Niagara Gas and St. Lawrence for the recovery of Niagara Gas' costs for transmitting the gas to the point of export. The Board believes the border price should represent Niagara Gas' purchase cost of gas plus a cost of service charge which would allow depreciation of the export facilities to be fully recovered during the term of the export licence plus a fair rate of return on the capital invested in the facilities.

Financing of Project

The estimated cost of the transmission facilities proposed by Niagara Gas and St. Lawrence is $2,543,000 of which some $448,000 represents the portion payable by Niagara Gas, the balance being payable by St. Lawrence. Both companies are wholly-owned subsidiaries of Consumers', and Niagara Gas requirements in this connection would be met by advances from the parent company.

In addition to construction of the United States portion of the transmission line, St. Lawrence has an extensive construction program for its distribution system, and the total construction requirements of that company

to the end of 1963 are estimated at $5,862,200. It is proposed that these requirements will be met from the proceeds of the following security issues:

200,000 Common Shares ($10 par value)	$2,000,000
20-Year Debentures	650,000
First Mortgage Bonds	3,000,000
	$5,650,000

Consumers' has committed itself to purchase the common stock and the debentures; and the other securities would be placed privately with United States institutional investors. A financial witness stated that no difficulty was anticipated in connection with the proposed sale of these securities. While Consumers' has agreed to furnish St. Lawrence with capital up to$5,000,000 through the purchase of common stock and debentures, it was estimated that the $2,650,000 referred to above would be sufficient. Consumers' will be called on to provide approximately $3,100,000 to finance that company's two subsidiaries and it was indicated that the company's established line of credit with Canadian chartered banks was ample to take care of this obligation.

It should be noted that Canadian investors will have no opportunity to acquire securities of either Niagara Gas or St. Lawrence. The common shares of both companies, however, will be wholly-owned by Consumers' and it was stated in evidence that more than 96 per cent of that company's shares are owned in Canada.

SECTION 11

INTERVENTIONS

The Alberta Gas Trunk Line Company Limited

The General Manager briefly reviewed the provincial legislation incorporating the company, the capital structure, distribution of shares both voting and non-voting and the method of electing the five directors who represent producers, exporters and distributors of gas. Two other directors are appointed by the government.

The facilities constructed to the end of 1959 in the Plains Division which serves Trans-Canada were described together with the proposed new construction in 1960, some of which is contingent upon the export of gas at Emerson being approved. Details were also given of the proposed Foothills Division system for completion in 1961 which will gather and transport gas for Alberta and Southern, Westcoast and Canadian-Montana if their applications for export licences are approved. These details appear in Map 4.

The company outlined its proposed construction program with estimated costs as follows:

(a) $13,664,240 for its Plains Division in 1960 including $4,940,000 attributable to the Emerson export and

(b) $108,041,000 for the Foothills Division including a line from Savanna Creek to Coleman.

Canadian Petroleum Association

The Canadian Petroleum Association, representing producers who are responsible for 97 per cent of the oil and gas production in Canada, filed a comprehensive brief in support of gas export.

Messrs. Connell and Erdman of the Reserves Committee presented estimates of proven and ultimate reserves which have been dealt with in the reserve section of this report.

Mr. Jones, a member of CPA's Special Gas Committee, discussed field prices and the netback to producers after gathering and processing costs were deducted. He took the Cessford field as an example, showing that the producers received 5.6 cents per million cubic feet after deducting gathering and processing charges of 3.74 cents and 15 per cent royalty from the average field price of 10.43 cents. He illustrated how transmission costs could be reduced through the operation of large diameter lines at high load factor. Mr. Jones also explained the pricing provisions of the gas purchase contracts.

Mr. Aaring introduced the part of the brief entitled, "The Importance of the Petroleum and Natural Gas Industry to the Canadian Economy". He estimated that the petroleum industry would spend $6.8 billion during the period 1959 to 1968 exclusive of expenditures on pipe lines and

refineries and related matters, but including $300 million for the development and processing of gas to meet present export applications. In the estimate of expenditures it was assumed that the current rate of exploration would be sufficient to maintain a healthy reserve position but if there were the incentive of further exports, exploration and development expenditures would be stepped up. Revenues for the period 1959 to 1968 were estimated to be $7.2 billion, including gas revenues of $491 million during the period 1961 to 1968 if the present export applications were granted. By 1968, annual revenue from oil and gas production was estimated to be $1,069 million as compared with $999 million without export.

Mr. White, President of Imperial Oil Limited, presented a brief on behalf of his company as a member, and on behalf of CPA. The brief directed the Board's attention to two reasons underlying opposition to the export of gas, and discussed the benefits to the country of an oil and gas industry which has incentives to carry out exploration and development at a high level.

The fear of running out of gas supplies was the first reason given for opposition. This was considered analagous to an attitude which has appeared from time to time over the last forty years, especially in the United States in relation to crude oil, and results from the failure to

differentiate between proven reserves on the one hand and ultimate reserves on the other. While there is no precise measurement of ultimate reserves, experience over a period of years regarding both crude oil and gas reserves has demonstrated that ultimate reserves are many times greater than proven reserves. Further, it has been demonstrated that if exploration activity is maintained, life of the reserves will also be maintained or increased.

The second reason given is fear that widespread sales of gas would engender substantial advances in consumer prices. This resulted from failure to place possible changes in the field price of gas in their proper perspective relative to the price paid by the consumers in major consuming areas, especially those outside the Prairie Provinces. The average consumer price in Vancouver, Toronto, and Montreal is approximately $1.25 per Mcf. Small consumers pay a higher price. In comparison, gas prices paid to the producer in Alberta range from 7 cents to 13.5 cents per Mcf after gathering, removal of liquids and impurities and delivery to the field gate. The maximum increase up to 1968 provided in any contract studied by Imperial Oil was 3.5 cents.

The foregoing price data illustrate the small proportion of the ultimate consumer price that is paid to the producer. The difference between field and consumer prices represents the great capital investment necessary to transport gas long distances and distribute it in the major centres.

The brief referred to the price protection provided in their respective jurisdictions by municipal, provincial, and federal authorities and by the long-term contracts distributors hold with their suppliers. Further, it pointed out that all major consuming centres are readily accessible, both to domestic and imported coal and fuel oil, which means that gas prices must be held to competitive levels. The brief concluded that the upward pressure on the field price of natural gas would be largely offset by competition from other fuels and the economies which gathering, transmission, and distribution companies would be able to effect through full utilization of their lines and facilities.

British Columbia Electric Company Limited

B. C. Electric submitted an intervention stating that the company serves 100,000 customers in the lower mainland of British Columbia with natural gas, and also liquefied petroleum gas in Victoria. The company supplies electricity and transit services directly and indirectly to 325,000 customers. The company purchases its gas from Westcoast.

It was contended that Westcoast's existing export commitments and estimated British Columbia requirements for 30 years total 6.746 trillion cubic feet. This was related to Westcoast's estimate of British Columbia reserves of approximately 3.059 trillion cubic feet, of which 1.7 trillion

cubic feet are under contract or option to Westcoast. An additional .7 trillion cubic feet in Alberta are under option or contract to Westcoast, making a total of 2.4 trillion cubic feet under contract or option. It was argued that when the contracted or optioned reserves of Westcoast are compared with those of other applicants, they are inadequate.

B. C. Electric further considered that Westcoast's estimate of British Columbia's requirements was low. More specifically the company contended there is insufficient provision of gas for power generation. This Board agrees with this contention and has taken it into consideration in estimating future markets of the province.

Mr. Robertson, Counsel for B. C. Electric, argued that the 36-inch line proposed to be built by Alberta Natural and the 30-inch line proposed to be built from Winnipeg to Emerson by Trans-Canada had capacities greater than necessary for the quantities of gas sought to be exported in their licence applications under Part VI of the Act. He asked the Board to guard against the possibility of Alberta and Southern or Trans-Canada extending their gathering systems into the Peace River Area from which Westcoast draws its gas.

<u>Southwest Alberta Development Association</u>

The Association was represented at the hearing by Mr. Deane R. Gundlock, M.P., who read to the Board the submission of that Association whose membership includes the municipal governments and chambers of commerce of southwest Alberta. The Association strongly favoured the export of natural gas which it claimed would increase exploration and drilling and revive the general prosperity of the oil and gas industry. The Association felt there was nothing to fear in an increased price to the Alberta consumer as any probable increase in price would be offset by increased prosperity in the area.

<u>Town of Bowness</u>

Mayor Fitzgerald-Moore of Bowness explained that the town's growth was due to the growth of the petroleum industry. He presented a resolution of the Town Council pointing out that a large portion of its operating revenue came from provincial grants which were in turn derived from revenues from the oil and gas industry; that large scale export was essential to the prosperity of the industry; that the Alberta consumer was adequately protected by provincial legislation; and that Bowness supported the export of natural gas at the earliest possible time.

Communities of the East Kootenays (Cranbrook, Kimberley, Fernie, Creston, Marysville and Chapman Camp).

These communities were represented by Mr. M. L. McFarlane, M.P., and Dr. Fraser, Chairman of the Natural Gas Committee of the East Kootenays. Dr. Fraser stated that the proposed line of Alberta Natural would be the only source of gas for service to these communities.

The second problem of the communities was cost, and they contended that the cost of spur lines to the boundaries of the municipalities should be included in the overall capital costs of Alberta Natural. It was argued that the cost of constructing 60 miles of small diameter pipe line would be minor when absorbed into the cost of constructing 1,400 miles of large diameter pipe line. (The 1,400 miles apparently includes 386 miles of Alberta Gas Trunk Foothills System, 105 miles of Alberta Natural, 614 miles of Pacific Gas Transmission and 296 miles of Pacific Gas and Electric terminating at Antioch, California.) It was submitted that the price of gas to the communities should not exceed the price of gas at the international boundary.

Westcoast stated in evidence that it was prepared to make gas available for service to these communities if such service proved economical. Westcoast presented an estimate showing cost of service, including lateral lines, to these communities, based on the experience of Inland

Natural to interior British Columbia communities. Without including the cost of gas, the lateral transmission and local distribution costs per Mcf were:

	1st Year $	5th Year $
Cranbrook	.71	.61
Kimberley - Residential and Commercial	.86	.74
- Industrial	.37	.26
Fernie	.96	.71
Creston	2.21	1.46

It was admitted that these estimates were probably on the high side and that it might be possible to pare costs as much as 25 per cent with a "poor boy" type of installation.

Counsel for Alberta and Southern in his final argument stated that a dangerous precedent would be established if the request of the East Kootenays was acceded to. He pointed out that Trans-Canada would be faced in Canada, and Pacific Gas Transmission in the United States, with this problem of supplying gas to communities at the expense of other customers.

The Board in calculating Canadian requirements has included provision for service to these East Kootenay communities. In the event that service is not instituted, section 60 of the National Energy Board Act provides for appropriate protection for their interests.

Province of Ontario

The Province of Ontario filed a submission and Mr. Clarkson, Deputy Minister of the Ontario Department of Energy Resources, appeared as a witness.

The brief asked the Board to consider the adequacy of reserves of natural gas for present and future needs before export was allowed. Recent experience had made the Province conscious of its energy demands and of its dependence on external sources of supply. The brief submitted that export to the western United States would encourage exploration and development of additional reserves in Canada. Mr. Clarkson stated that the Province did not oppose the applications presently before the Board. It was felt that gas exports would help develop new reserves and assure future supplies to Ontario. The brief asked for a close examination of proposals to export gas through facilities in eastern Canada and held that estimates of Canadian demands should be based on the highest forecasts.

It was pointed out in the submission that while sales of interruptible gas allow better overall load factors, every alternative, including use of underground storage, should be explored before allowing export of low priced interruptible gas. Mr. Clarkson did not object to the export of surplus interruptible gas.

The present working storage in Ontario was stated to be 22.5 billion cubic feet. The brief suggested that the feasibility of using other potential storage areas should be examined closely since it was estimated that working storage could be increased to about 85 billion cubic feet. The opinion was expressed that easy export of interruptible gas was detrimental to the incentive to develop other economically feasible storage areas.

Exception was taken to statements made in Niagara Gas' application to the effect that the proposal was the only feasible manner of supplying northern New York State. The brief also expressed misgivings about Canada becoming the sole source of supply for the growing market requirements of the area in New York State to be served through the Niagara Gas line.

It was submitted that, as a matter of principle, the selling price of exported gas should not be less than the price charged to the nearby Canadian consumers.

Saskatchewan Power Corporation

The Corporation submitted an intervention and an exhibit "Estimate of Natural Gas Requirements for Province of Saskatchewan 1960-1989". At the hearing Mr. David Cass-Beggs, the General Manager, gave evidence on the Corporation's behalf. The Corporation is the sole purchaser of natural gas produced within the Province and with minor exceptions the sole distributor throughout the Province. It operates 180 miles of

gathering line and 1,250 miles of transmission line. It estimates that the total requirements of natural gas for 1960-1989 inclusive would be 4.5 trillion cubic feet.

The witness stated that the estimated requirements for natural gas in Saskatchewan submitted by applicants before this Board were based on a report for Saskatchewan Power by the Fish Corporation. These estimates are substantially below the Corporation's own estimates of future provincial requirements.

The Corporation estimated the reserves of natural gas available in Saskatchewan at July 1, 1959, to be approximately 720 billion cubic feet. It did not foresee any further significant discoveries of dry gas but estimated some additional 155 billion cubic feet of associated gas would be produced by 1980, making a total of 875 billion cubic feet available to meet the Province's requirements.

In addition the Corporation has contracted with Trans-Canada for an additional 70 billion cubic feet from Alberta. The Corporation has negotiated also the purchase of a maximum volume of 695 billion cubic feet over a 30-year period from the Medicine Hat field in Alberta. Of this amount 145 billion have been resold to Trans-Canada. When the witness was cross-examined on the resale, he gave business judgment as the reason for the transaction. The Corporation pointed out that it has at present $70 million invested in

its facilities and that unless natural gas is discovered at a phenomenal rate in Saskatchewan the Province will become in a large measure dependent on outside sources. The Corporation contended that:

(1) presently proven reserves of natural gas in Canada are not more than adequate to meet 30 years future requirements;

(2) the National Energy Board must determine what level of proven and probable gas reserves is required before export is justified;

(3) in light of proven reserves and estimated requirements and uncertainty concerning increases in reserves there should be a cautious approach to gas export;

(4) before export is allowed there should be a minimum of proven reserves to cover 30 years of Canadian requirement and in order to provide incentive for exploration the Board should recommend that the Dominion Government should acquire proven reserves within the limit of economic feasibility;

(5) establishment of a minimum national reserve would involve an independent appraisal by the National Energy Board inasmuch as applicants had an interest in under-stating Canadian requirements and in over-stating reserves available;

(6) Canadian utilities should have a prior right to use gas licenced for export should other existing sources of gas available to Canadian utilities prove inadequate and that such a right would apply to any Canadian utility operating in an area traversed by or supplied with gas from the pipe line of any applicant.

New York State Natural Gas Corporation
and
Niagara Mohawk Power Corporation

New York Natural, a subsidiary of Consolidated Natural Gas Company, is incorporated in New York State and engaged in producing, purchasing, transporting and storing natural gas. Mohawk Power is a non-affiliated customer of New York Natural, incorporated in New York State to sell gas and electric services. Mohawk Power purchases all its gas from New York Natural under a requirements contract. Both these intervenors opposed the granting of the application of Niagara Gas for an export licence.

New York Natural and Mohawk Power have applications pending before the Public Service Commission of New York and the Federal Power Commission in competition with St. Lawrence, the company to which Niagara Gas proposes to deliver gas. The outcome will determine whether St. Lawrence or Mohawk Power may serve the contested area. Subject to the approval

of requisite regulatory authorities, New York Natural has agreed to supply Mohawk Power with all the natural gas required for the proposed area.

These intervenors expressed interest in securing interruptible gas from Canada. In anticipation of such supplies Mohawk Power had caused suitable pipe to be inserted at a cost of approximately $157,000 under the Iroquois lock of the St. Lawrence Seaway and had caused sleeves to be placed in the piers of the adjoining Iroquois Dam for the insertion of carrier pipe at a future date.

Evidence was submitted that, subject to existing commitments, Trans-Canada was prepared to supply gas on a combination of seller's option, seasonal, interruptible, off-peak or 'non-firm' basis. Witnesses testified that Mohawk Power's plan for supplying the contested distribution area depended basically on United States gas supplies. They argued, however, that a market for Canadian gas could be developed on a non-firm basis in northern New York State which could serve to improve the load factor of Trans-Canada's system.

Counsel for these intervenors, in opposing the application of Niagara Gas contended that the market to be served would be much larger than indicated by the applicant's estimate which was a projection at the estimated 1963

level of sales and thus excluded incremental growth thereafter. Since Niagara Gas' proposal would make the area wholly dependent on Canadian gas approval of this application, it was argued, would involve the acceptance of a much larger future commitment.

Northern Ontario Natural Gas Company Limited

NONG filed an intervention and was represented during part of the hearings. Messrs. Sedgwick and Taggart cross-examined several witnesses but the company withdrew after completing a contract with Trans-Canada. In requesting leave of the Board to withdraw its intervention, NONG stated that the new contract, which was filed with the Board, satisfied the matters raised in the original intervention.

Interventions, resolutions, letters and expressions of opinion in various forms were received from the following Ontario communities expressing concern over future supplies and prices of natural gas in Northern Ontario and supporting the NONG intervention:

Township of Teck, Town of Kapuskasing, City of Port Arthur, Port Arthur Chamber of Commerce, The North Eastern Ontario Municipal Association, Town of Sturgeon Falls, City Council of Sudbury, Town Council of Kenora, Industrial and Publicity Board of Kenora, Kenora Chamber of Commerce, Northeastern Ontario Development

Association, Northwestern Ontario Development Association, City of North Bay, Corporation of the City of Fort William, Town of Timmins, Town of New Liskeard, Corporation of the Town of Haileybury, Corporation of the Township of Whitney, Chamber of Commerce of Fort William, Association of Mining Municipalities of Northern Ontario.

These organizations withdrew their interventions subsequently to the completion of the contractual arrangements between NONG and Trans-Canada and no witnesses or counsel appeared for any of these communities or organizations.

National Coal Association et al

A joint intervention was filed on behalf of a group of organizations of the coal industry in the United States, namely: National Coal Association, Fuels Research Council Inc., United Mine Workers of America, The Chesapeake and Ohio Railway Company, Mid-West Coal Producers Institute, Inc., Upper Lake Docks Coal Bureau, Inc., Truax-Traer Coal Company, The National Coal Policy Conference Inc.

The intervenors submitted that their interest was consistent with the interest of the Canadian public in that they sought to ensure that the price charged by the applicants for gas exported by them to the United States would be just

and reasonable; and that the maintenance of a healthy United States coal industry was in the best interest of the Canadian public.

In connection with projected estimates of future Canadian market requirements, it was submitted that the potential interruptible markets in Canada were not adequately analyzed. The application of Trans-Canada to sell interruptible gas to Tennessee at Niagara was opposed and it was suggested that Trans-Canada should utilize storage facilities of Tennessee to store gas in the summer and bring it back into its system in the winter months.

It was further contended that, with the exception of Saskatchewan Power, all of Trans-Canada's customers in 1962 will be paying more per Mcf for their gas on an average than Midwestern because the contracts with Canadian distributors contain provisions for adjustments of prices to reflect tax or other regulatory increases whereas the Midwestern contract had no such provision. Further, it was stated, the Midwestern contract provided for a 1 cent per Mcf escalation increase every five years whereas the majority of Trans-Canada's purchase contracts provided for escalation of one-quarter cent per year, resulting in a one-quarter cent deficiency of revenue every five years per Mcf.

This argument appears to ignore the fixed prices in the long term contracts between Trans-Canada and its Canadian distributors and the ability of a long distance pipe line to absorb increases in the purchase price of gas without raising delivered prices.

Finally it was claimed that the area in the United States served by Midwestern is a highly competitive fuel area whereas California is dependent on large volumes of natural gas to meet its energy requirements and would be a more stable market for Canadian gas than the eastern and midwestern United States.

City of Calgary

The City of Calgary was represented by Mr. Helman as counsel, and by Mr. Davies, a witness. The position of the city was stated by Mr. Davies in these terms: "before export permits are approved, controls of some form should be provided as to supply and price to Canadian consumers of natural gas".

Mr. Davies filed with the Board a study prepared by him, indicating that on the basis of present reserves and estimates of trends in discovery there would not be sufficient gas to protect Canadian and export requirements and that "some (export) application (sic) must be refused". It was established during cross-examination of Mr. Davies

that he had made an error in estimating the requirements of Trans-Canada for both its Canadian and export markets. Further, he had included in his study potential future requirements of the export markets of the applicants. The Board gave him an opportunity to correct the figures in his study and suggested that in computing export requirements he include only the volumes for which export licences are sought. Mr. Davies presented a revised study reducing his estimate of overall requirements by about 50 per cent and withdrew his previous assertion that some export applications would of necessity have to be refused.

The City of Calgary also asked that some 1,131 billion cubic feet of gas be reserved for a suggested thermal electric power plant to supply the Calgary metropolitan area in the future. The City did not provide a witness who could be examined on the design and economic feasibility of the proposed plant. The Board adopted the estimates of Alberta's gas requirements shown in the Alberta Board report of December 1959. It is noted in the aforementioned report that the Alberta Board has investigated the matter of the proposed thermal electric power plant very thoroughly and that, after hearing various witnesses, it had included in the Alberta requirements a volume of gas for the plant which it considered reasonable and which was considerably less than that requested by the City.

Mr. Helman concerned himself with the field price of gas, the price to distributors, and the escalation, renegotiation and favoured nation clauses in gas purchase contracts. He contended that a control of transmission costs was useless without a control of field prices because higher field prices must be reflected in the prices paid by consumers.

He suggested that the National Energy Board Act was enacted to protect Canadian consumers and that, by means of a recommendation to the Minister under section 22 of the Act (this section provides that the Board may make recommendations to the Minister concerning energy matters over which the Parliament of Canada has jurisdiction), the Board should seek authority to regulate field prices if in the view of the Board it does not now have this power.

Alternatively, Mr. Helman suggested that the Board recommend to the Minister that the question of whether jurisdiction over field prices lies within the competence of a Provincial Legislature or with Parliament under the British North America Act, should be referred to the Supreme Court of Canada.

Mr. Helman took strong exception to the escalation and renegotiation clauses under the various gas purchase contracts which have been reviewed in the Board's discussion of the various applications.

He made specific reference to the contract between the Alberta Utilities and Trans-Canada where the Utilities will have to pay a weighted average field price for gas which excludes the ten-cent gas purchased prior to May 27, 1957. This contract was dated January 8, 1959 and may be termed 'an option to purchase' as it does not oblige the Utilities to take any gas.

Mr. Helman contended that there was discrimination against the Alberta consumers who would have to bear the impact of field price increases due to escalation as they would receive no benefit from the ability of long distance pipe lines to absorb such increases. He suggested that this might constitute unjust discrimination under sections 55 and 56 of the National Energy Board Act, which provide that a company shall not make any unjust discrimination in tolls, service or facilities against any person or locality and that the burden of proof that any discrimination is not unjust lies upon the company. The Board notes that sections 55 and 56 concern tolls, service and facilities: no reference is made to wellhead or field prices for gas nor does the definition of 'tolls' set forth in the Act have reference to such prices.

City of Edmonton

The City of Edmonton, through its solicitor, Mr. MacDonald, presented a brief expressing the view that although the City did not oppose the export of gas it was concerned with the effect on consumer gas prices of the escalation, favoured nation, and renegotiation types of clauses in the gas purchase contracts. He was also concerned with clauses dividing 'excess' earnings between the contracting parties.

The City asked the Board to give assurance that the approval of gas export now and the acceptance of the gas purchase contracts by the Board would be without prejudice to the City's right to challenge increased field prices affecting consumers before the Public Utility Board of Alberta or any other regulatory board having jurisdiction over such prices.

Comments on Field Prices and Provisions of Gas Purchase Contracts Relating to Price Increases

The matters raised by the Cities of Calgary and Edmonton and others with respect to the field prices of gas and the provisions in the gas purchase contracts whereby the aforesaid prices will be or may be increased, were spoken to by counsel for the Province of Alberta, the Alberta Utilities, CPA and by counsel for the applicants.

Mr. Frawley, representing the Province of Alberta, took the position that the regulation of the field price of gas produced in Alberta was within the exclusive jurisdiction of the Provincial Legislature. He referred to the provisions of section 72 of The Public Utilities Act, Chapter 267 of The Revised Statutes of Alberta 1955, as amended, which give the Board of Public Utility Commissioners the power to fix and determine the just and reasonable price to be paid for gas, inter alia, at the wellhead or delivered at a field gathering point.

Further in this regard, Mr. Frawley also drew the Board's attention to the Speech from the Throne at the opening of the 1960 Session of the Alberta Legislature, which he quoted as follows:

> "Legislation will be introduced to repeal the Public Utilities Act, replacing it with two statutes. One will embody the general regulatory powers conferred on the Board of Public Utility Commissioners and the other will set out the powers and responsibilities of the Board in the regulation of the gas industry".

Mr. Massie, counsel for the Alberta Utilities serving the Calgary and Edmonton areas, supported Mr. Frawley's position that the Province of Alberta had jurisdiction over field prices and, further, that as far as

Alberta consumers are concerned, the Province controlled the price of gas from the wellhead to the consumers' burner tip.

With respect to the fears of the City of Edmonton that approval of export by the Board might be construed as approving the gas purchase contracts, Mr. Massie stated:

> "Frankly, I find it difficult to imagine how it could be even reasonably contended that any order made by this Board now granting a permit under section 83 of your Act could be said to be a fixing or determination of field prices merely because the contracts have been filed as Exhibits."

He pointed out, as did Mr. Frawley, that if, at a later date, the Board were given jurisdiction over wellhead prices, it had the power under section 17 of the National Energy Board Act to review, change, or rescind any order or decision made by it.

Mr. Massie considered that the concern of the Cities of Edmonton and Calgary was premature in regard to the possible impact of the pricing provisions of the gas purchase contracts on the price his clients would have to pay under their contracts with the exporters. Neither Calgary nor Edmonton is presently using gas purchased from the exporters and will not do so for several years to come. He stated that when the time came to purchase such gas, a year's

notice of intention to buy gas would have to be given and the cities would then have ample time to make application for price determination.

Mr. McNeill, counsel for Trans-Canada, in reference to the contracts between his company and the Alberta Utilities, quoted extracts from the report of the Alberta Board in March 1959, as follows:

> "The concern expressed by counsel for the city of Calgary about the interpretation of certain provisions in the contracts between the Alberta Utilities and the exporters is not shared by the Board."

> "Under the circumstances, the Oil and Gas Conservation Board is unable to find that the price provisions in the contract are unreasonable or against the public interest."

Counsel for Alberta and Southern, Mr. MacKimmie, stated in essence that the Board did not have to decide whether or not there is jurisdiction to fix field prices. He contended that this Board is charged with the responsibility of looking at the whole general picture of export and its primary consideration is to ensure that the price at the border is just and reasonable and in the Canadian public interest.

Mr. Prothroe, counsel for Westcoast, supported the arguments put forth by the other counsel in regard to the City of Calgary's intervention.

Mr. Corbet, for CPA, emphasized that the producers, in negotiating gas sales contracts, wanted to recover the capital expenditures already made and receive enough revenue to continue exploration and development and, at the same time, earn a reasonable profit. Escalation clauses, in the opinion of CPA, provided for inflation and, in addition, were valid business arrangements based on time and volume. He pointed out that as the rate base of a pipe line is decreased through depreciation and the throughput increases, the ability of a pipe line to share increased revenues with the producers can be achieved without affecting the price to the ultimate consumers.

The Board's views in regard to jurisdiction over field prices and the terms of gas purchase contracts relating to price increases may be expressed as follows:

(1) it can find nothing in the National Energy Board Act which gives it power to regulate field prices;

(2) it does not agree that, under section 22 of the Act, it could make a recommendation to the Minister, as suggested by Mr. Helman, that the Board be given control of wellhead and field prices. This section limits the recommendations of the Board to 'measures

within the jurisdiction of the Parliament of Canada' relating to energy. If the Board were to make a recommendation such as proposed by Mr. Helman it would be assuming that control of wellhead and field prices was within the jurisdiction of Parliament;

(3) it would be premature for the Board to comment now on the impact which the pricing provisions in the gas purchase contracts may have on future wellhead and field prices of gas and, in turn, on distributor and consumer prices. If the contention of the Province of Alberta that its legislature has exclusive jurisdiction over field prices is sound and if it intends to exercise such jurisdiction, this Board can not foresee the steps which the Province may take in the future to control prices. Further, the Board is not presently in a position to judge the extent to which increases in wellhead or field prices may be absorbed by the gas transmission companies without any effect on prices to distributors;

(4) it does not consider that in approving export applications it is endorsing or approving gas purchase contracts received in evidence. The

Board required the production of gas purchase contracts to enable it to make an overall determination on the merits or otherwise of an application, and more particularly, to assess the reserves and deliverability of gas under the control of an applicant, and the cost of gas as a factor in export prices.

SECTION 12

SUMMARY OF DEMAND AND SUPPLY - DISPOSITION OF APPLICATIONS

Summary of Demand and Supply

The Board, before it submits for approval any licence to export gas, must satisfy itself that such gas does not exceed the surplus remaining after due allowance has been made for the reasonably foreseeable requirements for use in Canada, having regard to the trends in the discovery of gas in Canada. A summary of the demand and supply position, as it exists today, follows.

Canadian Requirements

The Board believes thirty years to be an appropriate period for the calculation of the reasonably foreseeable requirements in Canada. It estimates the Canadian demand for gas over the thirty-year period, 1960 to 1989, for domestic, commercial, and industrial purposes to be some 30.3 trillion cubic feet. Particulars of the market estimates appear in Section 2 and Table 1.

Established Reserves

The Board estimates the established reserves of gas as at December 31, 1959 to be in the order of 30 trillion cubic feet, having been calculated at 30.3 trillion cubic feet at 14.73 psia and a heating value of 1,000 btus per cubic foot.

It is wholly coincidental that this figure is the same as that arrived at for the foreseeable Canadian requirements.

Reserves are discussed in Section 3 and a tabulation of reserves by provinces is shown in Table 3.

Trends in Discovery of Gas

Having regard to the evidence before it, the advice of its staff and its own knowledge, and assuming that there will be incentive to exploration sufficient to result in the drilling of some 360 to 400 wildcat wells per year, the Board believes that the development of further established reserves can be expected at an averate rate of some 2.5 trillion cubic feet per annum for at least the next ten years, and thereafter on a somewhat decreasing scale. The initial disposable reserves of 30.3 trillion cubic feet established at the end of 1959 are expected to increase to approximately 92 trillion cubic feet by 1989.

Trends in discovery of gas are discussed in Section 3 and shown in Figure 1.

Provisions to Meet Canadian Requirements and Present Export Commitments

From Established Reserves: The Board considers that total Canadian requirements estimated to the 1963 level of demand and continuing at that level through to the end of 1980, amounting

to 12.3 trillion cubic feet, should be provided from established reserves. It considers that the increment in Canadian demand after 1963 until the end of 1980, and all Canadian demand from 1981 to 1989 inclusive, amounting to 21 trillion cubic feet, should be provided from the reserves which the trends of discovery indicate will become available. The provision of 12.3 trillion cubic feet for Canadian demand to the end of 1980 plus presently authorized exports of 2.1 trillion require the reservation from established reserves of 21 trillion to provide for annual and peak day deliveries. Subtracting the 21 trillion cubic feet from currently established reserves of 30.3 trillion indicates a current surplus of 9.3 trillion cubic feet.

From Future Reserves: In order to protect the remainder of the Canadian requirement to 1989 of 18.0 trillion cubic feet, some 24.6 trillion of future disposable reserves will be required to ensure annual and peak day deliveries.

Since it has been estimated that by 1989 initial disposable reserves will be 92 trillion cubic feet, since 21 trillion of established reserves have been allocated to protect Canadian demand and present export commitments to the end of 1980, and since a further 24.6 trillion of future reserves should be allocated to protect Canadian demand to 1989, it follows that some 46 trillion cubic feet would be

surplus at that time.

Particulars of these calculations appear in Section 4 and Table 8.

Surplus Gas

In order to get a proper perspective of surplus gas in relation to the existing demand and supply situation in Canada, it is necessary to consider the marketing pattern for gas, which involves giving separate consideration to British Columbia as compared with the other provinces from Alberta to Quebec.

As previously stated, there is an overall surplus of established reserves amounting to 9.3 trillion cubic feet for Canada as a whole.

If British Columbia is considered by itself, the established reserves fall short of the amount required to ensure annual and peak day deliveries to meet provincial demand as estimated to 1963 projected at that level to 1980, and the presently authorized gas exports. The deficiency appears to be about 0.9 trillion cubic feet. This is approximately the difference between the proved and probable reserves estimated by Westcoast and the established reserves as estimated by the Board for British Columbia. The Board believes, however, that with an aggressive program to develop known pools and one-well discoveries and with a reasonable

level of exploration, ample gas will become available to supply the British Columbia markets and the presently authorized exports from the province. When trends in future discoveries of gas are taken into consideration, there is expected to be a surplus of 7.8 trillion cubic feet over the cumulative reserves estimated to be necessary for the complete protection of British Columbia to 1989.

East of British Columbia, presently established reserves exceed requirements by some 10.2 trillion cubic feet. When trends in future discoveries of gas are taken into consideration, there is expected to be a surplus of some 38.6 trillion cubic feet over the cumulative reserves estimated to be necessary for the complete protection to 1989 of the area Alberta to Quebec.

Details of these calculations appear in Section 4 and, in particular, in the table on page 12 of that Section.

Applications for Export Licences in Relation to Surplus Established Reserves

The applications for gas export licences now before the Board are for a total volume of 6.7 trillion cubic feet. The total amount of reserves necessary to ensure annual and peak day deliveries of this volume is some 8.3 trillion cubic feet. Details follow:

Applicant	Export Volume Requested	Established Reserves Required to Meet Application
	Billions of Cubic Feet	
Trans-Canada		
(Emerson)	1,410	1,812
(Niagara Falls)	(No specific volumes)	
Alberta and Southern		
(Kingsgate)	3,826	4,563
Westcoast		
(Kingsgate)	1,100	1,497
Canadian-Montana		
(Cardston)	274	334
Niagara Gas		
(Cornwall)	74	114
Total	6,684	8,320

The above applications may be considered in the light of the 9.3 trillion cubic feet of established reserves estimated to be surplus at the present time and of a surplus of some 46 trillion cubic feet estimated for 1989 having regard to the trends in discovery of gas in Canada. It would thus be possible to grant the export licences without exceeding the surplus remaining after due allowance has been made for the reasonably foreseeable requirements for use in Canada.

Disposition of Applications

The Board has given due consideration to all the evidence presented to it and to the objections and representations made by all interested persons in respect of the applications for the exportation of gas. It has satisfied itself that the sum of the quantities of gas sought to be exported by the applicants does not exceed the surplus remaining after due allowance has been made for the reasonably foreseeable requirements for use in Canada, having regard to the trends in the discovery of gas in Canada. The Board has further satisfied itself that the price to be charged by each of the applicants, except Niagara Gas, for gas to be exported is just and reasonable in relation to the public interest.

Similarly, after hearing the evidence from the applicants and interested persons in respect of the applications for certificates of public convenience and necessity to construct and operate pipe lines, the Board is satisfied that such lines, except that proposed by Niagara Gas, are and will be required by the present and future public convenience and necessity. In coming to this conclusion, the Board took into consideration the availability of gas to the proposed pipe lines, the existence of actual or potential markets for the gas to be transmitted, the economic feasibility of the lines, the financial responsibility and financial

structure of the various applicants, the proposed methods of financing the lines and the extent to which Canadians will have an opportunity of participating in their financing, engineering and construction and any public interest that may be affected by the Board's disposition of these applications.

The Board is prepared to issue, subject to the approval of the Governor in Council, the following licences for the exportation of gas and certificates of public convenience and necessity in respect of pipe lines, with appropriate terms and conditions to be included therein:

1. To Trans-Canada Pipe Lines Limited

(a) a licence for the exportation of gas at a point on the international boundary line between Canada and the United States of America near Emerson in the Province of Manitoba, the licence to include the following terms and conditions:

(i) the term of the licence shall be for a period commencing on the date of issue and ending on the 14th day of May, 1981;

(ii) the quantity of gas that may be exported under the authority of the licence shall be not more than 204,000,000 cubic feet in any one day, nor more than 74,000,000,000 cubic feet in any

consecutive twelve-month period, nor more than 1,410,000,000,000 cubic feet during the term of the licence;

(iii) the licensee shall comply with the terms and conditions of the permits issued to it by the Oil and Gas Conservation Board of Alberta and numbered TC 54-1 dated May 14, 1954 (as amended), TC 59-2 dated January 29, 1959 (as amended), and TC 60-3 dated January 13, 1960;

(iv) the prices to be received from time to time by the licensee for the gas to be exported shall be not less than those prices provided for in the Precedent Agreement dated August 11, 1955 (as amended), between the licensee and Midwestern Gas Transmission Company, which was placed in evidence before the Board as Exhibit 7, Appendix C-17;

(v) the licensee shall satisfy the Board prior to June 1, 1960, that arrangements have been completed for financing the construction of all the facilities necessary for the exportation of gas under the authority of the licence and that such construction will commence not later than July 1, 1960, unless upon application

by the licensee, later dates are set by the Board and approved by the Governor in Council;

(vi) the effective commencement date of the exportation of gas under the licence shall be on or before December 31, 1960, unless upon application by the licensee, a later date is set by the Board and approved by the Governor in Council;

(b) a licence for the exportation of gas at a point on the said international boundary line near Niagara Falls in the Province of Ontario, the licence to include the following terms and conditions:

(i) the term of the licence shall be for a period commencing on the date of issue and ending on December 31, 1965;

(ii) the quantity of gas which may be exported under the authority of the licence shall be only such gas which the licensee has available after providing for the gas requirements of its customers in Canada and after delivering to Canadian storage facilities all gas which can be economically stored, but in no event shall the amount of gas to be exported exceed 204,000,000 cubic feet in any one day;

(iii) the price to be received from time to time by the licensee for the gas to be exported shall be not less than 37 cents per thousand cubic feet at a pressure of 15.025 psia and a temperature of 60° Fahrenheit;

(iv) the Board may at any time during the term of the licence without public hearing but with the approval of the Governor in Council limit the total annual volume of gas which may be exported, if the Board considers such limitation to be necessary or advisable in the public interest;

(v) with the prior consent of the Board, Trans-Canada may, under emergency conditions, export volumes of gas in excess of those authorized by the licence;

(c) a certificate of public convenience and necessity in respect of a 30-inch pipe line to be constructed by Trans-Canada and extending from a point on its existing pipe line near the Village of Ile des Chenes in the Province of Manitoba to a point on the international boundary line between Canada and the United States of America near Emerson in the said Province, a distance of approximately 50.7 miles, together with additional compressor stations, meter stations, and other works

connected therewith, as set forth in the application, to be installed on the proposed extension and on its existing pipe line (including the portion thereof owned by the Crown Corporation but operated by Trans-Canada).

This certificate is to include the condition that Trans-Canada shall satisfy the Board before June 1, 1960, that arrangements have been completed for financing the construction of the pipe line and that construction will be commenced not later than July 1, 1960, unless upon application by Trans-Canada later dates are set by the Board and approved by the Governor in Council.

The Board has noted that the facilities proposed by Trans-Canada to deliver gas for export at Emerson would have capacity substantially in excess of that required to deliver the quantities of gas for which an export licence is sought. The Board would make clear that its approval of the applications herein does not constitute nor imply any commitment in respect of any future application by Trans-Canada to export any additional gas at Emerson.

2. To Alberta and Southern Gas Co. Ltd.

a licence for the exportation of gas at a point on the international boundary line between

Canada and the United States of America, near Kingsgate, British Columbia, the licence to include the following terms and conditions:

(i) the term of the licence shall be for a period commencing on the date of issue and ending 25 years from the date of the first exportation of gas under the authority of the licence or on the 31st day of October, 1986, whichever is the sooner;

(ii) the quantity of gas that may be exported under the authority of the licence shall be not more than 458,750,000 cubic feet in any one day, nor more than 153,270,000,000 cubic feet in any consecutive twelve-month period, nor more than 3,826,000,000,000 cubic feet during the term of the licence;

(iii) the licensee shall comply with the terms and conditions of the permits issued to it by the Oil and Gas Conservation Board of Alberta and numbered AS 59-1 dated April 7, 1959, (as amended) and AS 60-2 dated January 13, 1960;

(iv) the prices to be received from time to time by the licensee for the gas to be exported shall be not less than the cost of service charge set forth in paragraph 12 of the contract, dated December 15, 1958, between the licensee and Pacific Gas Transmission Company, which was placed in evidence before the Board as Exhibit 20 - Vol. 1, B-2;

(v) the licensee shall satisfy the Board prior to September 1, 1960, that arrangements have been completed for financing the construction of all the facilities necessary for the exportation of gas under the authority of the licence and that such construction will commence not later than November 1, 1960, unless upon application by the licensee later dates are set by the Board and approved by the Governor in Council;

(vi) the effective commencement date of the exportation of gas under the licence shall be on or before December 31, 1961, unless upon application by the licensee a later date is set by the Board and approved by the Governor in Council.

In approving this application, the Board realizes that the licence is for the maximum term permitted under the Act, but is of the opinion that it is, on balance, advantageous to secure access at this time to the California market.

It is recognized that the transmission facilities of the project have capacity greater than that required for the amount of gas specified in the export application. The Board is aware that the applicant hopes to utilize this capacity in the future, but would emphasize that approval of this application can not be construed as in any way committing the Board to approval of any future application for incremental supplies of gas, whether put forward upon reason of better utilization of the transmission facilities or upon any other reasons.

3. To Alberta Natural Gas Company

a certificate of public convenience and necessity authorizing the applicant to construct a 36-inch pipe line for the transportation of gas which will follow a route commencing at its junction with the pipe line of The Alberta Gas Trunk Line Company Limited at a location in Section 17, Township 8, Range 5, west of the 5th Meridian in the Province of Alberta, thence generally in a southwesterly

direction through the Crow's Nest Pass in the Province of British Columbia and terminating at the point of junction with the pipe line to be constructed, owned and operated by Pacific Gas Transmission Company on the international boundary line between Canada and the United States of America near Kingsgate, British Columbia, a total distance of approximately 108 miles.

The certificate is to include a condition that Alberta Natural Gas Company shall satisfy the Board before September 1, 1960, that arrangements have been completed for financing the construction of the pipe line and that construction will be commenced not later than November 1, 1960, unless upon application by Alberta Natural Gas Company, later dates are set by the Board and approved by the Governor in Council.

4. <u>To Canadian-Montana Pipe Line Company</u>

(a) a licence for the exportation of gas at a point southeast of Cardston, Alberta, on the international boundary line in Township 1, Range 24, west of the 4th Meridian, the licence to include the following terms and conditions:

(i) the term of the licence shall be for a period commencing on the date of issue and ending 25 years from the date of the first exportation of gas under the authority of the licence or on the 31st day of October, 1986, whichever is the sooner;

(ii) the quantity of gas that may be exported under the authority of the licence shall be not more than 36,000,000 cubic feet in any one day, nor more than 10,950,000,000 cubic feet in any consecutive twelve-month period, nor more than 273,750,000,000 cubic feet during the term of the licence;

(iii) the prices to be received from time to time by the licensee for the gas to be exported shall be not less than the cost of service charge to be paid to Alberta and Southern Gas Co. Ltd. as set forth in paragraph 12 of the contract dated October 2, 1959, between Alberta and Southern Gas Co. Ltd. and the licensee, which was placed in evidence before the Board as Exhibit 36, D-1, plus the full cost of service incurred in transmitting the gas through the facilities of the licensee to the international boundary line as set forth in the letter

agreement dated October 6, 1959, between the licensee and Montana Power, which was placed in evidence before the Board as Exhibit 36, C-1;

(iv) the licensee shall satisfy the Board prior to September 1, 1960, that arrangements have been completed for financing the construction of all facilities necessary for the exportation of gas under the licence and that such construction will commence not later than November 1, 1960, unless upon application by the licensee, later dates are set by the Board and approved by the Governor in Council;

(v) the effective commencement date of the exportation of gas under the licence shall be on or before December 31, 1961, unless upon application by the licensee, a later date is set by the Board and approved by the Governor in Council;

(b) a certificate of public convenience and necessity authorizing the applicant to construct a 16-inch pipe line approximately 3 miles in length and extending from a point on the international boundary line between Canada and the United States of America in Township 1,

Range 24, west of the 4th Meridian, in the Province of Alberta, to the point of connection with the pipe line to be constructed by The Alberta Gas Trunk Line Company Limited in the aforesaid Township.

The certificate is to include a condition that Canadian-Montana Pipe Line Company shall satisfy the Board before September 1, 1960, that arrangements have been completed for financing the construction of the pipe line and that construction of the pipe line will be completed not later than December 31, 1961, unless upon application by the company, later dates are set by the Board and approved by the Governor in Council.

The term of the Canadian-Montana licence, as in the case of that of Alberta and Southern Gas Co. Ltd., is the maximum permitted by the Act. The Board, having regard to the fact that this project is closely interwoven with and dependent upon that of Alberta and Southern, and having regard to the quantities of gas involved, has concluded that it is not inconsistent with the public interest to grant the licence for the maximum term.

5. <u>To Westcoast Transmission Company Limited</u>

a licence for the exportation of gas at a point on the international boundary line between Canada and the United States of America near Kingsgate, British Columbia, the licence to include the following terms and conditions:

(i) the term of the licence shall be for a period commencing on the date of issue and ending 20 years from the date of the first exportation of gas under the authority of the licence or on the 31st day of December, 1982, whichever is the sooner;

(ii) the quantity of gas that may be exported under the authority of the licence shall be not more than 152,000,000 cubic feet in any one day, nor more than 51,000,000,000 cubic feet in any consecutive twelve-month period, nor more than 1,020,000,000,000 cubic feet during the term of the licence;

(iii) the licensee shall comply with the terms and conditions of the permit issued to it by the Oil and Gas Conservation Board of Alberta and numbered WC 59-3 dated the 7th day of April, 1959 (as amended);

(iv) the prices to be received from time to time by the licensee for the gas to be exported, shall be not less than the cost of service incurred by it in purchasing and transmitting the gas to Kingsgate, including an annual rate of return of 7½ per cent on the net investment in the facilities required from time to time for the exportation of gas in accordance with the letter agreement dated December 9, 1957, amending the letter agreement dated May 25, 1957, between the licensee and Pacific Northwest Pipeline Corporation (now El Paso Natural Gas Company), which letter agreements were placed in evidence before the Board as Exhibit 30, C-1;

(v) the licensee shall satisfy the Board prior to September 1, 1960, that arrangements have been completed for financing the construction of all the facilities necessary for the exportation of gas under the authority of the licence and that such construction will commence not later than November 1, 1960, unless upon application by the licensee, later dates are set by the Board and approved by the Governor in Council;

(vi) the effective commencement date of the exportation of gas under the licence shall be on or before December 31, 1961, unless upon application by the licensee, a later date is set by the Board and approved by the Governor in Council.

It will be noted that under clause (ii) of the proposed licence conditions, the volumes of gas authorized for export are less than those applied for by some 80 billion cubic feet during the term of the proposed licence. The reduced volumes correspond with those the company is authorized to remove from Alberta under permit WC 59-3, when converted to a 14.73 psia pressure base and after deducting the estimated gas requirements of the East Kootenay area, which the company stated it would make available.

In respect of Westcoast's application to export gas near Kingsgate, British Columbia, the Board is satisfied that the proposed export is in the public interest. This conclusion has been reached after careful consideration of Westcoast's history, present status and prospects.

Westcoast is now exporting gas at Sumas under authority of an export licence granted pursuant to The Exportation of Power and Fluids and Importation of Gas Act. Mr. McDonald, Vice-President of the Company, under questioning,

indicated his belief that the only way to improve the relationship between the export price of gas at Sumas and the price to the British Columbia mainland distributors is to increase the throughput of the company's line from northern British Columbia to Sumas.

Mr. McDonald stated that additional throughput could be achieved by increased export and British Columbia demand. He emphasized that the present application to export gas from southern Alberta was a 'sideline' as far as the company was concerned and that it will continue to concentrate its efforts in northeastern British Columbia. He affirmed that the export from southern Alberta would in no way impair the future marketing of British Columbia gas. He referred to the growing evidence of markets in the western United States and was positive that any surplus of British Columbia gas could be marketed as soon as it was available.

The fact remains, however, that there can be no further export of gas from British Columbia until substantial additional reserves become established. The Board has pointed out that the reserves as presently established are not adequate for the protection of British Columbia requirements and the authorized exports, a situation which it believes can and should be quickly remedied.

The Board feels that there has not been sufficient inducement in the past to explore for and develop gas in

British Columbia. It is confident that if steps are taken to ensure a reasonable level of exploration and development, substantial additional reserves of gas will be established. The Board is conscious of the desirability of increased utilization of Westcoast's existing facilities and will examine very critically any further applications to export gas to the El Paso system otherwise than from northern British Columbia.

The Application of Niagara Gas Transmission Limited

The Board respects the enterprise shown in developing a project for the distribution of gas in a new market in the United States and in bringing the project through substantial difficulties to the point at which it now stands. The Board is satisfied that the quantities of gas concerning which Niagara Gas here seeks an export licence do not exceed the surplus remaining after due allowance has been made for the reasonably foreseeable requirements for use in Canada having regard to the trends in the discovery of gas in Canada. The Board is also satisfied that the price proposed to be paid by Niagara Gas to Trans-Canada at the latter's delivery point is fair and reasonable in relation to the prices at which gas is available from Trans-Canada to its other customers in the same general area.

As was discussed in Section 10, the agreement

between Niagara Gas and St. Lawrence provides for recovery of less than the full costs estimated to be incurred by Niagara Gas over the life of the export licence in transmitting the gas from Trans-Canada's delivery point to the point of export. This is so whether those costs are calculated on the basis of depreciation at $1\frac{1}{2}$ per cent or at 5 per cent per annum (which latter rate in the view of the Board would be preferable if not essential in establishing the costs of gas exported under a twenty-year licence under a project wholly devoted to export). This shortfall in recovery of costs of export transmission would not be removed by a variation of the treatment to be given to the matter of capital cost allowance for taxation purposes.

Therefore the Board is not satisfied that the price to be charged by the applicant for the gas proposed to be exported is just and reasonable in relation to the public interest.

Section 83 of the Act requires the Board upon application for a licence to have regard to all considerations that appear to it to be relevant, in addition to requiring the Board to satisfy itself on the particular matters of supply and price. There are in this case certain other considerations which it appears to the Board are materially relevant.

The market estimates put forward on behalf of the

applicant make no provision for incremental demand in the market to be served beyond 1963. It would be a normal expectation that a well founded and well managed distribution operation, such as St. Lawrence would presumably be, would require incremental gas to meet load growth above the estimated 1963 level. Since, so far as the record indicates, Trans-Canada would be the sole source of supply for the area to be served by St. Lawrence, acceptance of the present application either would imply acceptance of some responsibility to supply, within a short period and thereafter, additional gas to meet the load growth of the area, or else would imply a rather casual view by the Board of the responsibilities of Canada in commencing a strictly limited supply of gas to a wholly dependent export market. Neither implication is acceptable to the Board.

On the basis of the record in this proceeding, the Board is not prepared to issue the export licence applied for by Niagara Gas. Consequently, of course, it would not be prepared to issue the certificate of public convenience and necessity applied for by Niagara Gas.

ADDENDUM

The Board here presents in consolidated form certain information which the Board has received in the course of its proceedings. It is brought together here as a matter of public interest.

1. The capital investment in Canada, in gas transmission facilities alone, which would directly follow approval of the various applications has been estimated as follows:

(a)	Trans-Canada	
	Emerson line	$ 6,764,000
	main line items	25,853,000
	Crown Corporation	4,554,000
	Alberta Gas Trunk	13,664,000
(b)	Alberta and Southern	
	Alberta Natural	36,371,000
	Alberta Gas Trunk	108,041,000
(c)	Westcoast	
	Alberta Gas Trunk	4,864,000
(d)	Canadian-Montana	205,000
	Alberta Gas Trunk [in (b)]	
	Total	$ 200,316,000

This estimate does not include expenditures in gathering facilities and processing plants which would be associated with the investment in the transmission lines. Any estimate of total capital investment would be increased very substantially by the inclusion of such additional investment; for example, Alberta and Southern estimated that the additional investment in its case would amount to $140 million.

2. The Canadian Petroleum Association estimated that investment in the oil and gas industry, after excluding the direct investment in pipe lines and other facilities relating to the particular applications for export licences and certificates of public convenience and necessity, would increase by some $300 million in the period to January 1969. These additional expenditures reflect only estimated new investment in field development and gas processing facilities. It was assumed that the current level of exploration would be sufficient to maintain a healthy reserve position to protect the domestic market and the existing and proposed export licences.

3. Approval of the applications would result in considerable earnings of United States dollars. It is not possible

to make precise calculations of the sums involved over the whole export period in view of escalation and other variable clauses in the export contracts.

It is estimated that earnings from gas exports under the present applications in 1963 would be:

	Annual Volume Billions of Cubic Feet		Value
	Maximum	Estimated	Millions of Dollars
Trans-Canada	74	71	20.0
Alberta and Southern	153	153	39.7
Westcoast	51	51	13.2
Canadian-Montana	11	11	2.6
Total			75.5

4. The Canadian Petroleum Association estimated that cumulative increases in gas revenues to the producers from such exports would amount to nearly $500 million for the period 1961 to 1968 inclusive and that total revenues to the industry over a 25 year period would be increased by some $1.85 billion. These figures exclude the cost of service which would be payable to the transmission companies for transporting the gas to the international boundary.

The Board confines its remarks regarding the above data to pointing out that the approval by the Governor in Council of its disposition of the applications would materially benefit the oil and gas industry at this stage of its development in Canada.

All of which is respectfully submitted,

I. N. McKinnon

Chairman

Robert D. Howland

Vice Chairman

H. L. Briggs

Member

Douglas M. Fraser.

Member

Dated at OTTAWA

March 21, 1960.

APPEARANCES

Applicants:

Trans-Canada (N. John McNeill, Q.C., Frank P. Layton, Q.C., D. Gordon Blair, R. John Ludgate)

Alberta and Southern and Alberta Natural (R.A. MacKimmie, Q.C.)

Canadian-Montana (Ronald C. Merriam, Q.C.)

Westcoast (D.P. McDonald, Q.C., John E. Prothroe)

Niagara Gas (W.L.N. Somerville, Q.C., G.E. Creber)

Intervenors:

Province of Alberta (J.J. Frawley, Q.C.)

Province of Ontario (J.A.W. Whiteacre)

City of Edmonton (Alan F. Macdonald, Q.C.)

City of Calgary (S.J. Helman, Q.C.)

Town of Bowness (Peter Fitzgerald-Moore)

The Municipalities of the East Kootenays (W.N. Fraser, M.L. McFarlane, M.P.)

Canadian Petroleum Association (J.B. Corbet, Q.C.)

National Coal Association (D.D. Carrick, Q.C., John A. McGrath)

B.C. Electric (A. Bruce Robertson, Q.C.)

Alberta Trunk (J.C. Mahaffy, Q.C.)

Saskatchewan Power (L.G. Ganne)

New York State Natural (G.D. Finlayson)

Niagara Mohawk (G.D. Finlayson)

The Alberta Utilities (B.V. Massie, Q.C.)

NONG (Joseph Sedgwick, Q.C., J.D. Taggart).

The following organizations filed interventions but were not represented at the hearings:

B.C. & Yukon Chamber of Mines

Vancouver Board of Trade

Southern California Gas Company

Fosca Oil Co. Ltd.

Various communications were received from the following communities and organizations:

Plains-Western Gas & Electric Co. Ltd.

Southwest Alberta Development Association

Edmonton Chamber of Commerce

Town of Olds

District Jaycees Chamber of Commerce, Olds

Town of Rimbey

Canadian Association of Oilwell Drilling Contractors

Peace River Chamber of Commerce

Village of Carstairs

Town of High River

Town of Okotoks

Town of Stettler

Town of Forest Lawn

Lethbridge Chamber of Commerce

Calgary Chamber of Commerce

Joint Crowsnest Pass Towns Committee

A Group of Citizens of the City of Calgary.

Appendix 1

STATISTICAL TABLES

APPENDIX 1

INDEX OF STATISTICAL TABLES

Glossary of Terms

MCF - Thousand cubic feet
MMCF - Million cubic feet
MMCFD - Million cubic feet per day
BCF - Billion cubic feet

TABLE I

ESTIMATE OF DEMAND FOR NATURAL GAS IN CANADA BY PROVINCES AND CATEGORY OF USE FROM 1960 TO 1989 INCLUSIVE

(BILLIONS OF CUBIC FEET AT STANDARD CONDITIONS 14.73 PSIA, 60°F, 1000 BTU/CF.)

		1960	1961	1962	1963	1964	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	CUMULATIVE TOTAL
	QUEBEC																															
(A)	DOMESTIC	4.9	9.3	12.2	15.1	20.2	22.8	24.9	27.1	29.2	31.5	33.8	36.2	38.4	41.3	43.8	46.3	48.5	51.6	53.8	56.8	59.6	63.0	65.9	69.6	72.7	73.7	74.8	76.1	77.3	81.0	1,361.4
(B)	COMMERCIAL	1.3	2.6	3.4	4.0	5.2	5.8	6.3	6.7	7.2	7.7	8.2	8.7	9.2	9.7	10.2	10.8	11.2	11.8	12.2	12.9	13.4	14.1	14.8	15.6	16.3	17.0	17.8	19.4	19.1	19.9	321.5
(C)	INDUSTRIAL – FIRM	1.3	2.5	3.9	4.6	5.5	5.9	6.2	6.5	7.1	7.5	8.1	8.7	9.3	10.0	10.8	11.5	12.3	13.2	14.0	15.0	16.0	17.2	18.6	19.9	21.3	23.4	24.5	25.5	26.5	27.8	384.6
(D)	– INTERRUPTIBLE	10.8	17.4	20.4	22.2	21.9	25.6	28.6	31.2	34.2	36.3	39.7	42.9	45.7	48.9	52.1	54.6	57.5	61.5	63.8	67.4	70.4	74.5	78.0	82.2	86.2	92.1	99.9	107.9	116.5	121.9	1,712.5
(E)	TOTAL	18.3	31.8	39.9	45.9	52.8	60.1	66.0	71.5	77.7	83.0	89.8	96.5	102.6	109.9	115.9	123.4	129.5	138.1	143.8	152.1	159.4	168.8	177.3	187.3	196.5	206.2	217.0	227.9	239.4	250.6	3,780.0
	ONTARIO																															
(F)	DOMESTIC	52.1	53.7	62.4	72.3	80.9	88.3	96.0	102.0	114.3	119.9	124.0	127.3	132.5	140.2	144.3	150.1	156.3	162.9	169.1	175.0	181.5	187.5	194.1	199.3	205.1	210.5	215.8	221.6	227.5	233.4	4,399.7
(G)	COMMERCIAL	10.2	10.5	11.8	13.4	14.5	15.5	16.6	17.3	19.0	20.0	20.9	21.6	23.3	24.9	26.4	28.1	29.8	31.8	33.7	35.7	37.8	39.8	42.1	44.2	46.6	48.9	51.1	52.7	54.5	55.7	898.0
(H)	INDUSTRIAL – FIRM	27.1	37.2	49.1	55.1	61.1	66.8	70.5	78.8	86.0	92.5	99.9	104.9	107.1	112.9	114.6	117.1	119.9	122.8	125.7	128.3	131.3	134.2	137.4	139.9	142.8	145.7	148.5	151.6	154.5	160.5	3,223.8
(I)	– INTERRUPTIBLE	24.7	30.9	38.6	42.1	45.4	46.6	47.5	49.9	52.9	57.4	62.4	65.8	68.6	68.3	70.5	73.2	76.1	78.9	82.0	84.8	88.7	91.2	94.5	97.7	100.7	104.3	107.9	111.5	115.4	117.4	2,195.9
(J)	NET INPUT INTO STORAGE	1.5	1.5	1.5	1.5	1.5	1.5	1.5	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	10.5
(K)	TOTAL	115.6	133.8	163.4	184.4	203.4	218.7	232.1	248.0	272.2	289.8	307.1	319.6	331.2	346.3	355.8	368.5	382.1	396.4	410.5	423.8	439.3	452.7	468.1	481.1	495.2	509.4	523.3	537.4	551.9	567.0	10,728.1
	MANITOBA																															
(L)	DOMESTIC	6.1	7.9	9.9	11.9	14.1	15.3	16.5	17.7	18.7	19.7	20.8	21.9	22.5	23.1	23.6	24.1	24.7	25.2	25.8	26.4	26.9	27.5	28.2	28.9	29.6	30.3	31.1	31.8	32.6	32.6	675.4
(M)	COMMERCIAL	2.1	2.5	2.6	2.9	3.2	3.4	3.7	3.9	4.2	4.4	4.6	4.9	5.2	5.4	5.6	5.9	6.1	6.3	6.6	6.8	7.1	7.3	7.6	7.9	8.1	8.3	8.6	8.9	9.2	9.2	172.4
(N)	INDUSTRIAL – FIRM	2.2	2.3	2.4	2.4	2.5	2.5	2.6	2.7	2.7	2.8	2.9	2.9	3.0	3.0	3.1	3.1	3.2	3.3	3.3	3.4	3.5	3.6	3.6	3.7	3.7	3.8	3.9	4.0	4.0	4.0	94.1
(O)	– INTERRUPTIBLE	3.0	3.5	4.2	4.7	4.8	5.1	5.3	5.5	5.7	5.9	6.0	6.3	6.5	6.7	6.9	7.0	7.1	7.3	7.5	7.6	7.8	7.9	8.1	8.2	8.4	8.6	8.7	8.9	9.1	9.1	201.4
(P)	TOTAL	13.4	16.2	19.1	21.9	24.6	26.3	28.1	29.8	31.3	32.8	34.3	36.0	37.2	38.2	39.2	40.1	41.1	42.1	43.2	44.2	45.3	46.3	47.5	48.6	49.8	51.0	52.3	53.6	54.9	54.9	1,143.3
	SASKATCHEWAN																															
(Q)	DOMESTIC	11.5	13.2	14.7	16.1	17.3	18.5	19.4	20.2	21.0	21.8	22.7	23.5	24.3	25.0	25.7	26.5	27.4	28.2	29.0	29.9	30.7	31.5	32.2	32.9	33.8	34.6	36.0	37.0	38.0	38.9	781.5
(R)	COMMERCIAL	2.5	2.7	2.9	3.1	3.3	3.5	3.6	3.7	3.8	3.9	4.0	4.1	4.2	4.3	4.4	4.5	4.6	4.7	4.8	4.9	5.0	5.1	5.2	5.3	5.4	5.5	5.8	6.0	6.1	6.3	133.2
(S)	INDUSTRIAL – FIRM	5.0	5.4	5.8	6.3	6.8	7.3	7.8	8.4	9.0	9.6	10.1	10.7	11.3	11.9	12.5	13.0	13.6	14.3	15.0	15.6	16.3	17.0	17.8	18.6	19.2	19.9	20.0	20.5	21.1	21.6	391.4
(T)	– INTERRUPTIBLE	11.0	11.1	11.4	11.7	12.2	12.7	13.8	14.9	16.0	17.1	16.2	19.3	20.4	21.6	22.8	24.0	25.0	26.0	27.0	28.0	29.0	30.0	31.0	32.0	33.0	34.0	34.6	35.7	36.6	37.6	697.9
(U)	TOTAL	30.0	32.4	34.8	37.2	39.6	42.0	44.6	47.2	49.8	52.4	55.0	57.6	60.2	62.8	65.4	68.0	70.6	73.2	75.8	78.4	81.0	83.6	86.2	88.8	91.4	94.0	96.6	99.2	101.8	104.4	2,004.0
	ALBERTA																															
(V)	DOMESTIC	39.6	42.3	44.9	46.4	48.2	50.1	52.0	53.3	54.8	55.8	57.5	58.5	59.5	60.6	61.6	62.7	63.6	64.8	65.9	67.0	68.2	69.4	70.4	71.7	72.9	74.1	75.5	76.6	78.0	79.2	1,844.6
(W)	COMMERCIAL	28.6	30.3	31.6	33.1	34.6	36.2	37.0	37.9	38.7	39.7	40.5	41.5	42.2	43.0	43.7	44.5	45.2	45.9	46.8	47.6	48.4	49.2	50.0	50.8	51.7	52.6	53.5	54.4	55.7	56.9	1,311.8
(X)	INDUSTRIAL – FIRM	89.1	98.9	106.5	110.6	116.6	123.0	129.8	136.7	143.8	151.3	158.9	167.0	170.0	172.8	175.8	178.6	181.5	184.8	187.9	190.9	194.4	197.6	200.8	204.4	207.9	211.5	214.9	218.5	222.4	226.7	5,071.6
(Y)	– INTERRUPTIBLE	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
(Z)	TOTAL	157.3	171.5	181.0	190.1	199.4	209.3	218.8	227.9	237.0	246.8	256.9	267.0	271.7	276.4	281.1	285.8	290.3	295.5	300.6	305.5	311.0	316.2	321.2	326.9	332.5	338.2	343.9	349.5	356.1	362.8	8,228.2
(AA)	SUB-TOTAL	334.6	385.7	438.2	479.5	519.6	556.4	589.6	624.4	668.0	704.8	743.1	776.7	802.9	833.6	858.4	885.8	913.6	945.3	973.9	1004.0	1,036.0	1,067.6	1,100.3	1,132.7	1,165.4	1,198.8	1,233.1	1,267.6	1,304.1	1,339.7	25,883.6
(BB)	PIPE LINE FUEL AND LOSSES	4.0	11.7	14.5	16.5	18.4	20.3	22.2	24.0	26.2	28.0	29.8	31.4	32.8	34.3	35.8	37.2	38.6	40.3	41.7	43.4	45.0	46.7	48.3	50.1	51.6	53.5	55.4	57.3	59.2	61.1	1,079.5
(CC)	TOTAL DEMAND EAST OF B.C.	338.6	397.4	452.7	496.0	538.2	576.7	611.8	648.4	694.2	732.8	772.9	808.1	835.7	867.9	894.2	923.0	952.2	985.6	1015.6	1047.4	1,081.0	1,114.3	1,148.6	1,182.8	1,217.2	1,252.3	1,288.5	1,324.9	1,363.3	1,400.8	26,963.1
(DD)	PEAK DAY DEMAND (MMCFD)	1,802	2,072	2,151	2,575	2,785	2,982	3,147	3,331	3,540	3,733	3,931	4,097	4,215	4,375	4,503	4,645	4,772	4,938	5,080	5,235	5,394	5,555	5,724	5,893	6,054	6,225	6,403	6,593	6,767	6,954	
	BRITISH COLUMBIA																															
(EE)	DOMESTIC	11.1	13.0	16.5	19.1	21.6	23.9	26.4	28.1	29.7	31.4	33.1	34.6	35.8	37.0	38.3	39.5	40.8	42.5	43.4	44.6	46.0	47.3	48.8	50.3	51.8	53.4	55.1	56.8	58.5	60.3	1,138.7
(FF)	COMMERCIAL	4.7	5.4	6.5	7.4	8.1	9.3	10.2	10.9	11.6	12.2	12.9	13.4	13.9	14.4	14.9	15.4	15.8	16.5	16.9	17.4	17.9	18.4	19.0	19.6	20.2	20.8	21.4	22.1	22.7	23.5	443.3
(GG)	INDUSTRIAL – FIRM	2.0	2.3	2.7	3.2	3.8	4.4	4.6	4.9	5.1	5.3	5.6	5.8	6.1	6.4	6.7	7.1	7.4	7.7	8.1	8.4	8.8	9.2	9.6	10.0	10.5	11.0	11.4	12.0	12.5	13.1	215.7
(HH)	– INTERRUPTIBLE	6.0	7.0	8.1	19.6	31.3	41.3	42.0	42.6	43.3	44.0	44.8	45.6	46.4	47.3	48.2	49.2	50.1	51.2	52.2	53.3	54.4	55.7	56.8	58.2	59.5	60.9	62.4	64.0	65.6	67.3	1,378.5
(II)	TOTAL	23.8	27.7	33.8	49.3	64.8	78.9	83.2	86.5	89.7	92.9	96.4	99.4	102.2	105.1	108.1	111.2	114.1	117.9	120.6	123.7	127.1	130.6	134.2	138.1	142.0	146.1	150.3	154.9	159.3	164.2	3,176.1
(JJ)	PIPE LINE FUEL AND LOSSES	0.8	1.0	1.2	1.7	2.3	2.8	2.9	3.0	3.1	3.3	3.4	3.5	3.6	3.7	3.8	3.9	4.0	4.1	4.2	4.3	4.4	4.6	4.7	4.8	5.0	5.1	5.3	5.4	5.6	5.7	111.2
(KK)	UNALLOCATED	2.0	2.0	2.0	2.0	2.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	85.0
(LL)	TOTAL DEMAND	26.6	30.7	37.0	53.0	69.1	64.7	89.1	92.5	95.8	99.2	102.6	105.9	108.8	111.6	114.9	118.1	121.1	125.0	127.8	131.0	134.5	138.2	141.9	145.9	150.0	154.2	158.6	162.3	167.9	172.9	3,372.3
(MM)	PEAK DAY DEMAND (MMCFD)	138	160	196	282	367	445	472	491	510	528	548	564	577	592	607	621	635	655	665	680	694	710	727	744	762	782	800	821	841	863	
(NN)	TOTAL CANADIAN DEMAND	365.2	428.1	489.7	549.0	607.3	661.4	700.9	740.9	790.0	832.0	875.7	914.0	944.5	979.7	1009.1	1,041.1	1,073.3	1,110.6	1,143.4	1,178.4	1,215.5	1,252.5	1,290.5	1,328.7	1,367.2	1,406.5	1,447.1	1,488.2	1,531.2	1,573.7	30,335.4
(OO)	TOTAL PEAK DAY DEMAND (MMCFD)	1940	2,232	2,547	2,857	3,152	3,427	3,619	3,822	4,050	4,261	4,479	4,661	4,792	4,967	5110	5,266	5,407	5,593	5,745	5,915	6,088	6,265	6,451	6,637	6,816	7,007	7,203	7,414	7,608	7,817	

NATIONAL ENERGY BOARD,
MARCH 1960.

TABLE 2

ESTIMATE OF DEMAND FOR NATURAL GAS IN THE EAST KOOTENAY AREA OF B.C. 1963-1989

(QUANTITIES IN MILLIONS OF CUBIC FEET AT 14.73 PSIA AND 60^{0}F, 1000 BTU/CF)

	(A)	(B)	(C)	(D)	(E)	(F)	(G)
				DEMAND			
EAR	TOTAL POPULATION	ACCESSIBLE POPULATION	CONSUMPTION PER ACCESSIBLE POPULATION (MCF)	RESIDENTIAL AND COMMERCIAL	INDUSTRIAL	TOTAL	CUMULATIVE
963	-	-	-	378	440	818	-
964	-	-	-	504	440	944	1,762
965	-	-	-	672	440	1,112	2,874
966	-	-	-	755	440	1,195	4,069
967	-	-	-	839	440	1,279	5,348
968	47,400	30,810	31.3	964	440	1,404	6,752
969	49,200	31,980	33.2	1,062	440	1,502	8,254
970	51,100	33,215	35.2	1,169	440	1,609	9,863
971	53,000	34,450	36.4	1,254	440	1,694	11,557
972	55,000	35,750	36.4	1,301	440	1,741	13,298
973	57,100	37,180	36.4	1,353	440	1,793	15,091
974	59,300	38,545	36.4	1,403	440	1,843	16,934
75	62,000	40,300	36.4	1,467	440	1,907	18,841
76	64,300	41,795	36.4	1,521	440	1,961	20,802
77	66,700	43,355	36.4	1,578	440	2,018	22,820
78	69,200	44,980	36.4	1,637	440	2,077	24,897
79	71,800	46,670	36.4	1,677	440	2,117	27,014
80	74,500	48,425	36.4	1,763	440	2,203	29,217
81	77,300	50,245	36.4	1,829	440	2,269	31,486
82	80,200	52,130	36.4	1,898	440	2,338	33,824
83	83,200	54,080	36.4	1,969	440	2,409	36,233
84	86,400	56,160	36.4	2,044	440	2,484	38,717
85	89,700	58,305	36.4	2,122	440	2,562	41,279
86	93,100	60,515	36.4	2,203	440	2,643	43,922
87	96,600	62,790	36.4	2,286	440	2,726	46,648
88	100,200	65,130	36.4	2,371	440	2,811	49,459
89	104,000	67,600	36.4	2,461	440	2,901	52,360
TAL	-	-	-	40,480	11,880	52,360	

URCE: ESTIMATED MARKET REQUIREMENTS FOR NATURAL GAS, PROVINCE OF BRITISH COLUMBIA, 1960 - 1989 INCLUSIVE - WESTCOAST TRANSMISSION COMPANY LIMITED, NOVEMBER, 1959. TOTAL POPULATION FOR THE KOOTENAY AREA IS GIVEN IN THE SUPPLEMENTARY SHEET "ESTIMATE OF POPULATION - PROVINCE OF BRITISH COLUMBIA 1960 - 1989". IT IS STATED ON PAGE 2 OF THE MAIN SOURCE THAT 65 PERCENT OF TOTAL POPULATION IN THE INLAND SYSTEM IS ACCESSIBLE TO GAS. APPLYING THIS PERCENTAGE TO THE KOOTENAY POPULATION GIVES THE ACCESSIBLE POPULATION IN THAT AREA. THE SUPPLEMENTARY SHEET "PROJECTED REQUIREMENTS" - INLAND NATURAL GAS CO. LTD. AREA" GIVES FIGURES FOR THE CONSUMPTION FOR RESIDENTIAL AND COMMERCIAL USE COMBINED PER ACCESSIBLE POPULATION. THIS HAS AGAIN BEEN APPLIED TO THE KOOTENAY ACCESSIBLE POPULATION ALONE.

THE CONSTANT INDUSTRIAL FIGURE IS THAT FOR THE COMINCO PLANT AT KIMBERLY, SHOWN UNDER TAB 8-1 IN VOLUME I OF THE WESTCOAST SUBMISSION. THIS SOURCE ALSO GIVES FIRM FIGURES FOR RESIDENTIAL AND COMMERCIAL REQUIREMENTS DURING THE YEARS 1963 - 1967 INCLUSIVE, SO THAT THE CALCULATIONS SHOWN ABOVE ARE NOT NECESSARY FOR THIS PERIOD.

FRUARY 26, 1960.
N IONAL ENERGY BOARD.

TABLE 3

ESTABLISHED NATURAL GAS RESERVES IN CANADA[A]

AS OF 31 DECEMBER, 1959

(TRILLIONS OF CUBIC FEET)

PROVINCE	RESERVES[B]
BRITISH COLUMBIA	2.2
ALBERTA	26.9
SASKATCHEWAN	1.0
ONTARIO	0.2
TOTAL CANADA[A]	30.3

NOTES

(A) EXCLUSIVE OF YUKON AND NORTHWEST TERRITORIES. NEGLIGIBLE RESERVES IN MANITOBA, QUEBEC AND NEW BRUNSWICK.

(B) RESERVES CALCULATED AT STANDARD CONDITIONS, NAMELY, AT 14.73 PSIA, 60°F, 1000 BTU/CF.

NATIONAL ENERGY BOARD, MARCH, 1960.

TABLE 4

COMPARISON OF ESTIMATES [A] OF FUTURE NATURAL GAS RESERVES

(TRILLIONS OF CUBIC FEET)

(1)		(2)	(3)	(4)	(5)	(6)
		SOURCE OF ESTIMATE				
		TRANS-CANADA	ALBERTA & SOUTHERN	WESTCOAST	ALTA. OIL & GAS CONS. BD.	NATIONAL ENERGY BD.
(1) (2)	ALBERTA	77.7 (D)(1988)	72.9 (D)(1986)	(I)	47.7 (H)(1969) 90.0 (ULT.)	76.7 (J)(1989)
(3) (4)	B.C.	(I)	22.9 (E)(1986)	24.0 (G)(1989) 62.0 (ULT.)	(I)	15.2 (1989)
(5) (6)	SASK.	2.5 (B)	3.5 (F)(1986)	(I)	(I)	2.9 (1989)
(7) (8)	WEST.PROV'S.	(I)	99.3 (1986)	(I)	(I)	94.8 (J)(1989)
(9) (10)	ONTARIO	0.5 (C)(1988)	(I)	(I)	(I)	0.5 (1989)
(11)	TOTAL TO YEAR SHOWN	(I)	99.3 (1986)	(I)	(I)	95.3 (J)(1989)
(12)						

NOTES:

(A) ESTIMATES OF CUMULATIVE INITIAL DISPOSABLE RESERVES FOR YEARS SHOWN, WERE SUBMITTED BY APPLICANTS AND OTHERS. SEE TEXT FOR DERIVATION OF NATIONAL ENERGY BOARD FIGURES.

(B) ULTIMATE GAS RESERVES OF APPROXIMATELY 3.9 TCF CAN BE CALCULATED BASED ON ASSUMPTION THAT 3.1 BILLION BBLS. OIL WILL ULTIMATELY BE DISCOVERED, BUT APPLICANT FELT 2.5 TCF ULTIMATE RESERVES MORE REALISTIC.

(C) BASED ON ONTARIO FUEL BOARD'S FIGURE OF 0.225 TCF AT DECEMBER 31, 1958.

(D) DERIVED BY INTERPOLATION OF ALBERTA BOARD'S SEPT. 1958 FORECAST OF GROWTH OF ORIGINAL ESTABLISHED RESERVES

(E) BASED ON RATIO OF VOLUMES OF SEDIMENTS IN B.C. RELATIVE TO ALBERTA, ASSUMED TO BE 31.5%.

(F) ASSUMES ORIGINAL RESERVES IN SASKATCHEWAN TO INCREASE BY 0.1 TCF PER YEAR.

(G) FROM EXTRAPOLATION OF DATA ON WILDCAT WELLS DRILLED TO DATE AND CUMULATIVE INITIAL DISPOSABLE RESERVES, ASSUMING 55 WILDCATS PER YEAR.

(H) REPORT TO THE LIEUTENANT-GOVERNOR-IN-COUNCIL, PROVINCE OF ALBERTA, DECEMBER 1959.

(I) NO FIGURE SUBMITTED.

(J) FIGURES INCLUSIVE OF PRODUCTION PRIOR TO JANUARY 1, 1960.

NATIONAL ENERGY BOARD, MARCH, 1960.

TABLE 5

TRENDS IN WILDCAT DRILLING AND GROWTH OF INITIAL ESTABLISHED NATURAL GAS RESERVES, BY YEARS, IN NORTHEAST BRITISH COLUMBIA

(BILLIONS OF CUBIC FEET)

(1)	(2)	(3)	(4)	(5)	(6)	(7)
YEAR	WILDCAT WELLS DRILLED		INITIAL ESTABLISHED RESERVES AT DATE OF DISCOVERY		INITIAL ESTABLISHED RESERVES AT DATE OF DISCOVERY PER WILDCAT	
	YEAR	CUMUL.	YEAR	CUMUL.	YEAR	CUMUL.
PRECEEDING 1950		13	12.4	12.4	1.0	1.0
1950	7	20	5.0	17.4	0.7	0.9
1951	8	28	15.0	32.4	1.9	1.2
1952	10	38	330.0	362.4	33.0	9.5
1953	18	56	143.6	506.0	8.0	9.0
1954	20	76	291.9	797.9	14.6	10.5
1955	29	105	157.7	955.6	5.4	9.0
1956	24	129	191.8	1147.4	8.0	8.9
1957	36	165	153.7	1301.1	4.3	7.9
1958	40	205	527.0	1828.1	13.2	8.9
NOV.1/59	43	248	349.0	2177.1	8.1	8.8

NATIONAL ENERGY BOARD, MARCH, 1960.

TABLE 6

ESTIMATED NATURAL GAS REQUIREMENTS TO BE MET FROM BRITISH COLUMBIA RESERVES

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)	(25)	(26)	(27)	(28)	(29)
YEAR	TOTAL BRITISH COLUMBIA REQUIREMENTS			DELIVERIES AT SUMAS UNDER WESTCOAST CONTRACT			NORTHWEST ALBERTA GAS UNDER PERMIT TO WESTCOAST			ALBERTA GAS ALLOCATED FOR DELIVERY AT SUMAS			B.C. GAS ALLOCATED FOR DELIVERY AT SUMAS			NORTHWEST ALBERTA GAS SUPPLIED TO B.C. MARKETS			SOUTHWEST ALBERTA GAS SUPPLIED TO B.C. MARKETS			B.C. MARKETS SUPPLIED FROM B.C.			TOTAL REQUIREMENTS SUPPLIED FROM B.C. RESERVES			YEAR
	ANNUAL BCF	PEAK MMCFD	L.F. %	ANNUAL BCF	PEAK MMCFD	L.F. %	ANNUAL BCF	PEAK MMCFD	L.F. %	ANNUAL BCF	PEAK MMCFD	L.F. %	ANNUAL BCF	PEAK MMCFD	L.F. %	ANNUAL BCF	PEAK MMCFD	L.F. %	ANNUAL BCF	PEAK MMCFD	L.F. %	ANNUAL BCF	PEAK MMCFD	L.F. %	ANNUAL BCF	PEAK MMCFD	L.F. %	
1960	26.6	138	52.8	103.7	315	90	50.5	190	72.8	40.1	141	78.0	63.6	174	100.0	11.8	62	52.1				14.8	76	53.3	78.4	250	86.0	1960
1961	30.7	160	51.0	103.7	315	90	50.5	190	72.8	38.9	137	78.0	64.8	178	100.0	13.0	66	54.0				17.7	94	51.7	82.5	272	82.5	1961
1962	37.0	196	51.7	103.7	315	90	50.5	190	72.8	37.2	133	76.6	66.5	182	100.0	14.7	70	57.5				22.3	126	48.5	88.8	308	79.0	1962
1963	53.0	282	51.5	103.7	315	90	50.5	190	72.8	33.4	123	74.4	70.3	192	100.0	18.5	80	63.3	0.8	5	43.8	33.7	197	46.8	104.0	389	73.3	1963
1964	69.1	367	51.6	103.7	315	90	50.5	190	72.8	30.4	114	73.0	73.3	201	100.0	21.5	89	66.2	0.9	6	41.1	46.7	272	47.1	120.0	473	69.5	1964
1965	84.7	445	52.0	103.7	315	90	50.5	190	72.8	27.8	104	73.3	75.9	211	98.4	24.1	99	66.6	1.1	7	43.1	59.5	339	48.1	135.4	550	67.4	1965
1966	89.1	472	51.8	103.7	315	90	50.5	190	72.8	27.2	102	73.0	76.5	213	98.5	24.7	101	67.0	1.2	8	41.2	63.2	363	47.8	139.7	576	66.3	1966
1967	92.5	491	51.6	103.7	315	90	50.5	190	72.8	26.6	100	73.0	77.1	215	98.2	25.3	103	67.3	1.3	9	39.6	65.9	379	47.5	143.0	594	65.9	1967
1968	95.8	510	51.4	103.7	315	90	50.5	190	72.8	26.2	99	72.5	77.5	216	97.8	25.7	104	67.8	1.4	10	38.4	68.7	396	47.5	146.2	612	65.5	1968
1969	99.2	528	51.3	103.7	315	90	50.5	190	72.8	25.8	97	73.0	77.9	218	97.9	26.1	106	67.5	1.5	11	37.4	71.6	411	47.6	149.5	629	65.3	1969
1970	102.8	548	51.2	103.7	315	90	50.5	190	72.8	25.2	95	72.7	78.5	220	97.3	26.7	108	67.8	1.6	11	39.8	74.5	429	47.6	153.0	649	64.6	1970
1971	105.9	564	51.4	103.7	315	90	50.5	190	72.8	25.0	94	72.9	78.7	221	97.6	26.9	109	67.6	1.7	12	38.8	77.3	443	47.8	156.0	664	64.3	1971
1972	108.8	577	51.6	103.7	315	90	50.5	190	72.8	24.6	93	72.5	79.1	222	97.7	27.3	110	68.0	1.7	12	38.8	79.8	455	48.0	158.9	677	64.3	1972
1973	111.8	592	51.7	103.7	315	90	50.5	190	72.8	24.3	91	73.2	79.4	224	97.2	27.6	112	67.5	1.8	13	37.9	82.4	467	48.3	161.8	691	64.1	1973
1974	114.9	607	51.9	103.7	315	90	50.5	190	72.8	24.0	90	73.1	79.7	225	97.0	27.9	113	67.8	1.8	13	37.9	85.2	481	48.6	164.9	706	64.1	1974
1975	118.1	621	52.1	103.7	315	90	50.5	190	72.8	23.6	89	72.7	80.1	226	97.0	28.3	114	68.0	1.9	14	37.2	87.9	493	48.8	168.0	719	64.1	1975
1976	121.1	635	52.2	103.7	315	90	50.5	190	72.8	23.4	88	72.9	80.3	227	96.9	28.3	115	67.4	2.0	15	36.6	90.8	505	49.2	171.1	732	64.1	1976
1977	125.0	655	52.3	86.4	315	90	50.5	190	72.8	20.6	78	72.4	65.8	237	76.1	30.5	118	70.8	2.0	15	36.2	92.5	522	48.6	158.3	759	57.2	1977
1978	127.8	665	52.6				50.5	190	72.8							51.1	196	71.5	2.1	15	38.4	74.6	454	45.2	74.6	454	45.1	1978
1979	131.0	680	52.7				50.2	190	72.6							50.8	196	71.0	2.1	15	38.4	78.1	469	45.7	78.1	469	45.7	1979
1980	134.5	694	53.1													0.2	6	71.0	2.2	16	37.6	132.1	672	54.0	132.1	672	54.0	1980
1981	138.2	710	53.3																2.3	17	37.1	135.9	693	53.7	135.9	693	53.7	1981
1982	141.9	727	53.5																2.3	17	37.1	139.6	710	53.9	139.6	710	53.9	1982
1983	145.9	744	53.7																2.4	18	36.5	143.5	726	54.3	143.5	726	54.3	1983
1984	150.0	762	53.9																2.5	19	36.1	147.5	743	54.4	147.5	743	54.4	1984
1985	154.2	782	54.1																2.6	20	35.5	151.6	762	54.5	151.6	762	54.5	1985
1986	158.6	800	54.3																			158.6	800	54.3	158.6	800	54.3	1986
1987	163.3	821	54.5																			163.3	821	54.5	163.3	821	54.5	1987
1988	167.9	841	54.7																			167.9	841	54.7	167.9	841	54.7	1988
1989	172.9	863	54.9																			172.9	863	54.9	172.9	863	54.9	1989
TOTAL	3372.3			1849.3			1009.7			504.3			1345.0			531.0			41.2			2800.1			4145.1			

NOTE: QUANTITIES AT 14.73 PSIA, $60^{0}F$, 1000 BTU/CF.

NATIONAL ENERGY BOARD, MARCH, 1960.

5008—16

TABLE 7

ESTIMATED NATURAL GAS REQUIREMENTS (A) OF CANADA EAST OF BRITISH COLUMBIA

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
YEAR	REQUIREMENTS PROVINCE OF ALBERTA			REQUIREMENTS EAST OF ALBERTA			IMPORTS FROM U.S.A. (B)		STORAGE ETC. (C)	NET REQUIREMENTS EAST OF ALBERTA			NET REQUIREMENTS EAST OF B.C.			YEAR
	ANNUAL BCF	PEAK MMCFD	L.F. %	ANNUAL BCF	PEAK MMCFD	L.F. %	ANNUAL BCF	PEAK MMCFD	PEAK MMCFD	ANNUAL BCF	PEAK MMCFD	L.F. %	ANNUAL BCF	PEAK MMCFD	L.F. %	
1960	157.3	927	46.0	181.3	875	56.8	5.5	0	222	075.8	653	73.8	333.1	1,580	57.7	1960
1961	171.5	991	47.0	225.9	1,081	57.3	5.5	0	264	220.4	817	73.8	391.9	1,808	59.3	1961
1962	181.0	1,057	47.0	271.7	1,294	57.5	5.5	0	322	266.2	972	74.8	447.2	2,029	60.4	1962
1963	190.1	1,120	47.0	305.9	1,455	57.6	5.5	0	376	300.4	1,079	76.1	490.5	2,999	61.1	1963
1964	199.4	1,177	47.0	338.8	1,608	57.7	5.5	0	412	333.3	1,196	76.3	532.7	2,373	61.5	1964
1965	209.3	1,238	47.0	367.4	1,744	57.7	5.5	0	454	361.9	1,290	76.8	571.2	2,528	61.8	1965
1966	216.8	1,282	47.0	393.0	1,865	57.7	5.5	0	466	387.5	1,399	75.9	606.3	2,681	62.1	1966
1967	227.9	1,337	47.0	420.5	1,994	57.7	5.5	0	514	415.0	1,480	76.8	642.9	2,817	62.5	1967
1968	237.0	1,375	47.0	457.2	2,165	57.8	5.5	0	546	451.7	1,619	76.6	688.7	2,994	62.9	1968
1969	246.8	1,434	47.0	486.0	2,299	57.8	5.5	0	574	480.5	1,725	76.3	727.3	3,159	63.1	1969
1970	256.9	1,491	47.0	516.0	2,440	57.8			606	516.0	1,834	77.0	772.9	3,325	63.7	1970
1971	267.0	1,540	47.0	541.1	2,557	55.7			641	541.1	1,916	77.3	808.1	3,456	64.0	1971
1972	271.7	1,549	48.0	564.0	2,666	58.1			666	564.0	2,000	77.3	835.7	3,549	64.4	1972
1973	276.4	1,578	48.0	591.5	2,797	57.9			696	591.5	2,101	77.3	867.9	3,679	64.6	1973
1974	281.1	1,604	48.0	613.1	2,899	57.9			726	613.1	2,173	77.3	894.2	3,777	64.8	1974
1975	285.8	1,631	48.0	637.2	3,014	57.9			756	637.2	2,258	77.3	923.0	3,889	65.0	1975
1976	290.3	1,640	48.0	661.9	3,132	57.9			786	661.9	2,346	77.3	952.2	3,986	65.4	1976
1977	295.5	1,673	48.0	690.1	3,265	57.9			816	690.1	2,449	77.3	985.6	4,122	65.6	1977
1978	300.6	1,701	48.0	715.0	3,379	57.9			846	715.0	2,533	77.5	1,015.6	4,234	65.8	1978
1979	305.5	1,728	48.0	741.9	3,507	58.0			876	741.9	2,631	77.3	1,047.4	4,359	65.9	1979
1980	311.0	1,756	48.0	770.0	3,638	59.6			908	770.0	2,730	77.3	1,081.0	4,486	66.1	1980
1981	316.2	1,786	48.0	798.1	3,769	58.0			946	798.1	2,823	77.3	1,114.3	4,609	66.2	1981
1982	321.2	1,815	48.0	827.4	3,909	58.2			978	827.4	2,931	77.4	1,148.6	4,746	66.4	1982
1983	326.9	1,849	48.0	855.9	4,044	58.0			1,016	855.9	3,028	77.4	1,182.8	4,877	66.6	1983
1984	332.5	1,876	48.0	884.7	4,178	58.0			1,051	884.7	3,127	77.5	1,217.2	5,003	66.6	1984
1985	338.2	1,908	48.0	914.1	4,317	58.1			1,086	914.1	3,231	77.6	1,252.3	5,139	66.7	1985
1986	343.9	1,942	48.0	944.6	4,461	58.1			1,114	944.6	3,347	77.4	1,288.5	5,289	66.7	1986
1987	349.5	1,974	48.0	975.4	4,619	57.9			1,161	975.4	3,458	77.2	1,324.9	5,432	66.9	1987
1988	356.1	2,009	48.0	1,007.2	4,758	58.1			1,196	1,007.2	3,562	77.7	1,363.3	5,571	67.1	1988
1989	362.8	2,050	48.0	1,038.0	4,904	58.1			1,228	1,038.0	3,676	77.4	1,400.8	5,726	67.2	1989
TOTALS	8,228.2			18,734.9			55.0			16,679.9			26,908.1			

NOTE: (A) QUANTITIES AT 14.73 PSIA, 60°F, 1,000 BTU/CF. (B) INTERMITTENT IMPORT AT WINDSOR, ONTARIO. (C) INCLUDES STORAGE, PEAK SHAVING AND LINE PACK.

NATIONAL ENERGY BOARD, MARCH, 1960.

TABLE 8

FUTURE NATURAL GAS REQUIREMENTS OF CANADA PLUS SUBSISTING EXPORT COMMITMENTS AND THE ESTIMATED RESERVES NECESSARY TO SUPPLY THESE REQUIREMENTS

(BCF – BILLION CUBIC FEET)

(MMCFD – MILLION CUBIC FEET PER DAY)

(1) MARKET AREA	(2) PERIOD OF REQUIREMENT	(3) DELIVERIES DURING PERIOD TO MEET ESTIMATED DEMAND BCF	(4) TERMINAL PEAK DAY RATE P_N MMCFD	(5) RESERVES DELIVERY RATIO F BCF/MMCF	(6) RESERVES REQUIRED FOR TERMINAL PEAK $1.3FP_N$ BCF	(7) TOTAL GAS IN PLACE NECESSARY TO MEET REQUIREMENT BCF	(8) RATIO OF DISPOSABLE GAS TO GAS IN PLACE K BCF/BCF	(9) DISPOSABLE GAS NECESSARY TO MEET REQUIREMENT BCF	(10) ESTABLISHED RESERVES REQUIRED BCF	(11) FUTURE RESERVES REQUIRED BCF	
(1) BRITISH COLUMBIA (NET)	JAN.1/60 TO DEC.31/80 (B)	661.4	197	3.0	768	1,429	0.85	1,215	1,215		(1)
(2)	JAN.1/60 TO DEC.31/89	2,800.1	863	3.0	3,366	6,166	0.85	5,240		4,025	(2)
(3) ALBERTA	JAN.1/60 TO DEC.31/80	5,180.9	1,756	2.2	5,022	10,208	0.82	8,366	8,366		(3)
(4)	JAN.1/60 TO DEC.31/89	8,228.2	2,050	2.2	5,863	14,091	0.82	11,555		3,189	(4)
(5) CANADA, EAST OF ALBERTA (NET)	JAN.1/60 TO DEC.31/80 (B)	6,069.6	1,079	2.4	3,367	9,436	0.84	7,926	7,926		(5)
(6)	JAN.1/60 TO DEC.31/89	18,679.9	3,676	2.4	11,469	30,149	0.84	25,325		17,399	(6)
(7) CANADIAN MONTANA PIPE LINE COMPANY PERMIT	JAN.1/60 TO MAY 13/74 (C)	250.0						250	250		(7)
(8) PEACE RIVER TRANSMISSION COMPANY PERMIT NO. 1	JAN.1/60 TO JULY 13/80										(8)
(9) PEACE RIVER TRANSMISSION COMPANY PERMIT NO. 2	JAN.1/60 TO OCT.1/76	25.6	13	1.7	29	55	0.88	48	48		(9)
(10) WESTCOAST TRANSMISSION CO. LTD. PEACE RIVER (ALBERTA) PERMIT	JAN.1/60 TO DEC.31/79	1,009.7	190	1.7	420	1,430	0.88	1,257	1,257		(10)
(11) WESTCOAST TRANSMISSION CO. LTD. (SUMAS) LICENCE (B.C. PORTION)	JAN.1/60 TO OCT. /77	1,345.0	237	3.0	924	2,269	0.85	1,930	1,930		(11)
(12) TOTAL									20,992	24,613	(12)

NOTES: (A) QUANTITIES AT STANDARD CONDITIONS 14.73 PSIA, 60°F, 1000 BTU/CF.

(B) LEVELLED AFTER 1963 AT 1963 RATE.

(C) ALBERTA PERMIT EXPIRES MAY 13/74.

NATIONAL ENERGY BOARD, MARCH, 1960.

TABLE 9

FUTURE NATURAL GAS REQUIREMENTS(A) OF APPLICANTS, AND THE ESTIMATED RESERVES NECESSARY TO SUPPLY THESE REQUIREMENTS

(BCF — BILLION CUBIC FEET)

(MMCFD — MILLION CUBIC FEET PER DAY)

	(1) APPLICANT	(2) EXPORT QUANTITY REQUESTED BY APPLICANT FOR ENTIRE PERIOD BCF	(3) BTU PER CUBIC FOOT OF GAS AVAILABLE TO APPLICANT	(4) EQUIVALENT EXPORT QUANTITY AT STANDARD CONDITIONS	(5) TERMINAL DATE OF REQUESTED EXPORT LICENCE	(6) TERMINAL PEAK DAY RATE P_N MMCFD	(7) RESERVES DELIVERY RATIO F BCF/MMCFD	(8) RESERVES REQUIRED FOR TERMINAL PEAK $1.3FP_N$ BCF	(9) TOTAL GAS IN PLACE REQUIRED TO MEET LICENCE BCF	(10) RATIO OF DISPOSABLE GAS IN PLACE K BCF/BCF	(11) DISPOSABLE GAS NECESSARY TO MEET APPLICATION BCF	
(1)	ALBERTA & SOUTHERN GAS CO. LTD. (KINGSGATE)	3,826	1010	3,864	OCT. 31, 1985	464	2.0	1,206	5,070	0.90	4,563	(1)
(2)	CANADIAN MONTANA PIPE LINE CO. (CARDSTON)	274	1010	277	OCT. 31, 1985	36	2.0	94	371	0.90	334	(2)
(3)	NIAGARA GAS TRANSMISSION LTD. (CORNWALL)	74	1030	76	JUNE 30, 1980	18	2.4	56	132	0.86	114	(3)
(4)	TRANS-CANADA PIPE LINES LTD. (EMERSON)	1,410	1030	1,452	MAY 14, 1981	210	2.4	655	2,107	0.86	1,812	(4)
(5)	TRANS-CANADA PIPE LINES LTD. (NIAGARA)	(c)									(c)	(5)
(6)	WESTCOAST TRANSMISSION CO. LTD. (KINGSGATE)	1,100	1000	1,100	FEB. 29, 1984	165	2.8	601	1,701	0.88	1,497	(6)
(7)	TOTAL										8,320	(7)

NOTE: (A) COLUMNS (4) TO (11) AT STANDARD CONDITIONS 14.73 PSIA, 60°F, 1000 BTU/CF.

(B) CORRECTED TO EQUIVALENT PIPELINE GAS.

(C) APPLICATION IS FOR SELLER'S OPTION INTERRUPTIBLE GAS, WITH NO QUANTITIES SPECIFIED.

NATIONAL ENERGY BOARD, MARCH, 1960.

Appendix 2

FIGURES

APPENDIX 2

INDEX OF FIGURES

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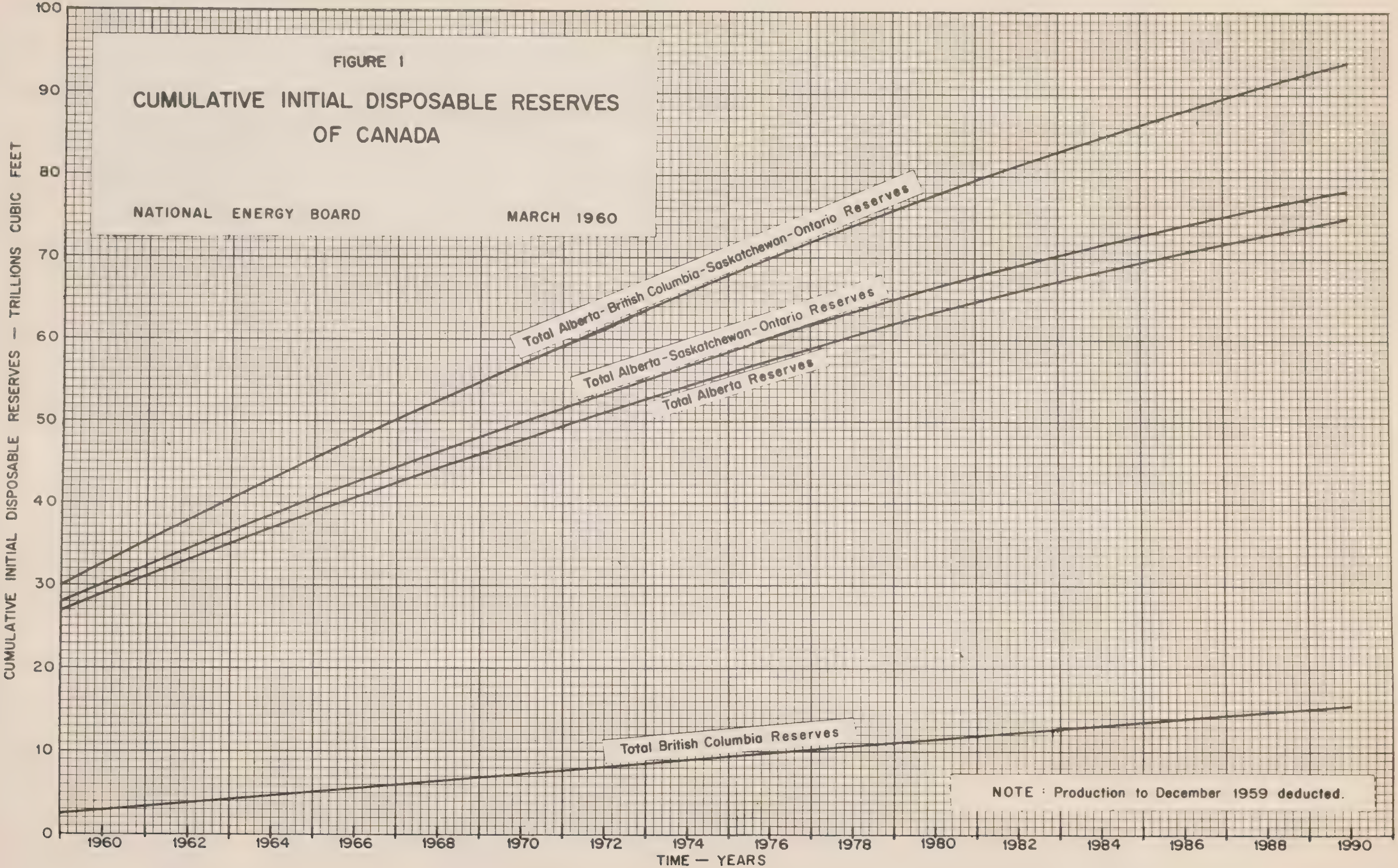
FIGURE 1
CUMULATIVE INITIAL DISPOSABLE RESERVES OF CANADA
NATIONAL ENERGY BOARD
MARCH 1960
CUMULATIVE INITIAL DISPOSABLE RESERVES — TRILLIONS CUBIC FEET
0
10
20
30
40
50
60
70
80
90
100
TIME — YEARS
1960
1962
1964
1966
1968
1970
1972
1974
1976
1978
1980
1982
1984
1986
1988
1990
Total Alberta-British Columbia-Saskatchewan-Ontario Reserves
Total Alberta-Saskatchewan-Ontario Reserves
Total Alberta Reserves
Total British Columbia Reserves
NOTE : Production to December 1959 deducted.

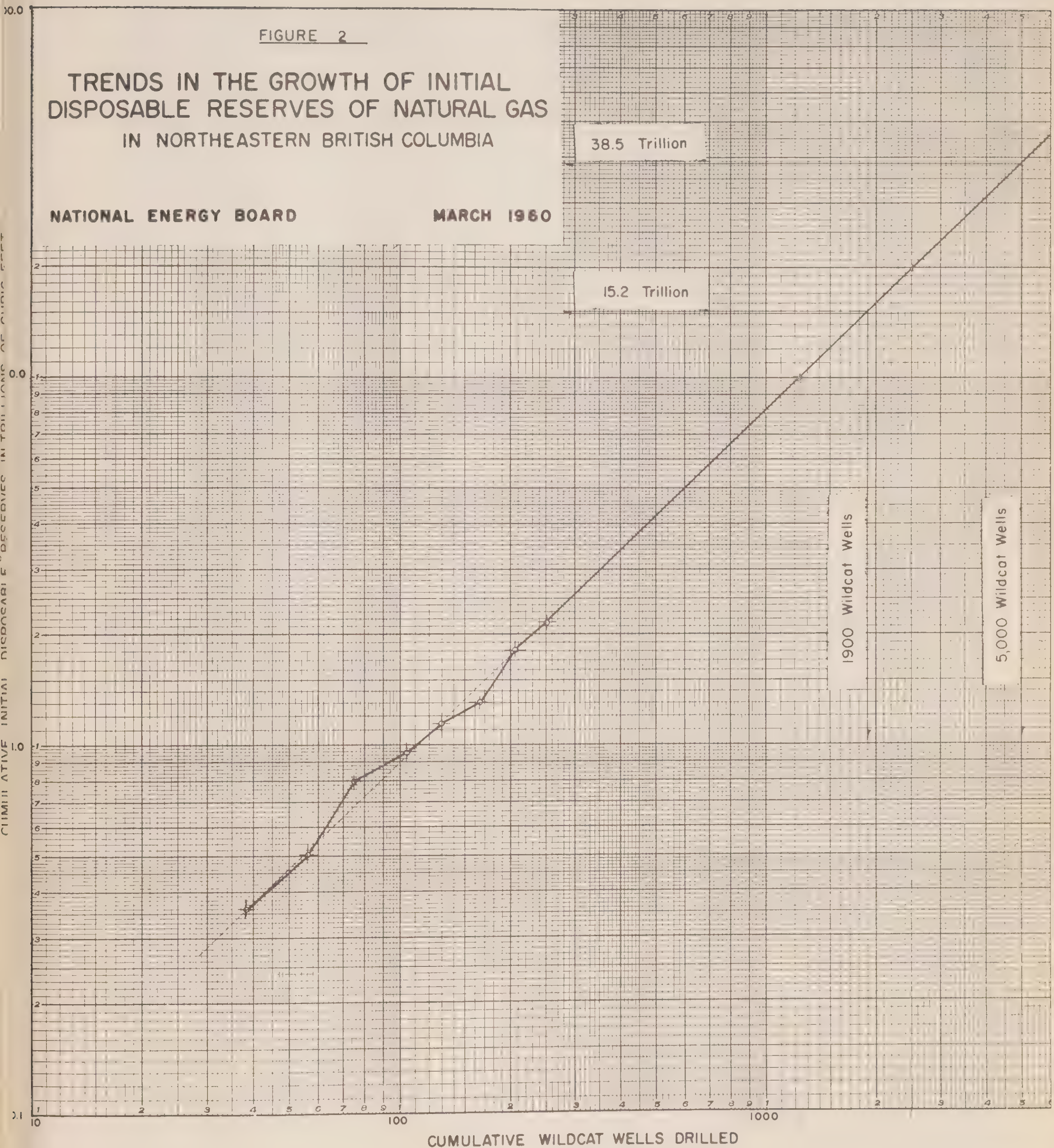
FIGURE 2
TRENDS IN THE GROWTH OF INITIAL DISPOSABLE RESERVES OF NATURAL GAS IN NORTHEASTERN BRITISH COLUMBIA
NATIONAL ENERGY BOARD
MARCH 1960
38.5 Trillion
15.2 Trillion
1900 Wildcat Wells
5,000 Wildcat Wells
10
100
1000
1.0
CUMULATIVE WILDCAT WELLS DRILLED

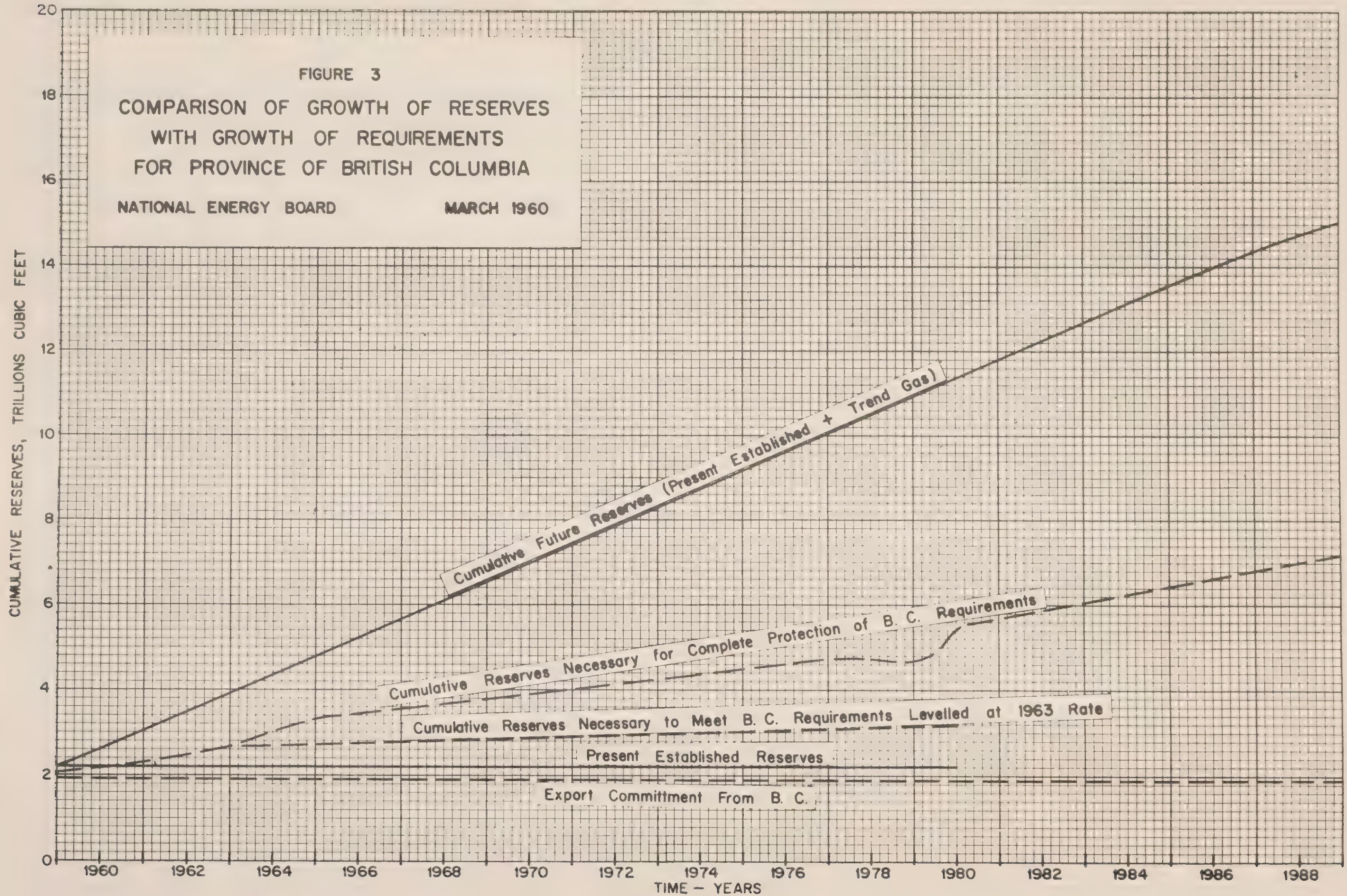
FIGURE 3
COMPARISON OF GROWTH OF RESERVES
WITH GROWTH OF REQUIREMENTS
FOR PROVINCE OF BRITISH COLUMBIA
NATIONAL ENERGY BOARD
MARCH 1960
Cumulative Future Reserves (Present Established + Trend Gas)
Cumulative Reserves Necessary for Complete Protection of B. C. Requirements
Cumulative Reserves Necessary to Meet B. C. Requirements Levelled at 1963 Rate
Present Established Reserves
Export Committment From B. C.
CUMULATIVE RESERVES, TRILLIONS CUBIC FEET
0
2
4
6
8
10
12
14
16
18
20
TIME — YEARS
1960
1962
1964
1966
1968
1970
1972
1974
1976
1978
1980
1982
1984
1986
1988

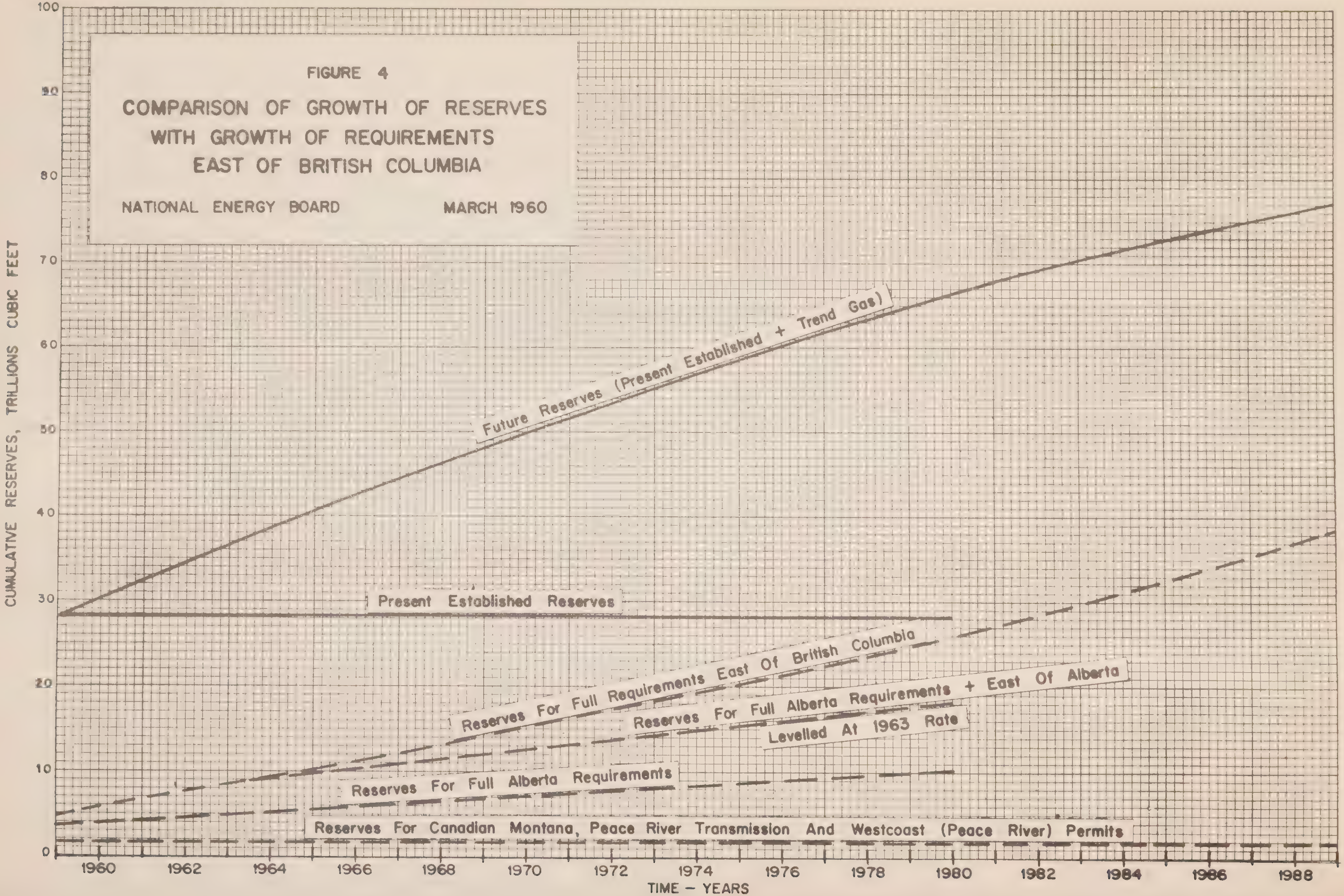

FIGURE 4
COMPARISON OF GROWTH OF RESERVES
WITH GROWTH OF REQUIREMENTS
EAST OF BRITISH COLUMBIA
NATIONAL ENERGY BOARD
MARCH 1960
CUMULATIVE RESERVES, TRILLIONS CUBIC FEET
TIME – YEARS
Future Reserves (Present Established + Trend Gas)
Present Established Reserves
Reserves For Full Requirements East Of British Columbia
Reserves For Full Alberta Requirements + East Of Alberta
Levelled At 1963 Rate
Reserves For Full Alberta Requirements
Reserves For Canadian Montana, Peace River Transmission And Westcoast (Peace River) Permits

Appendix 3

MAPS

APPENDIX 3

INDEX OF MAPS

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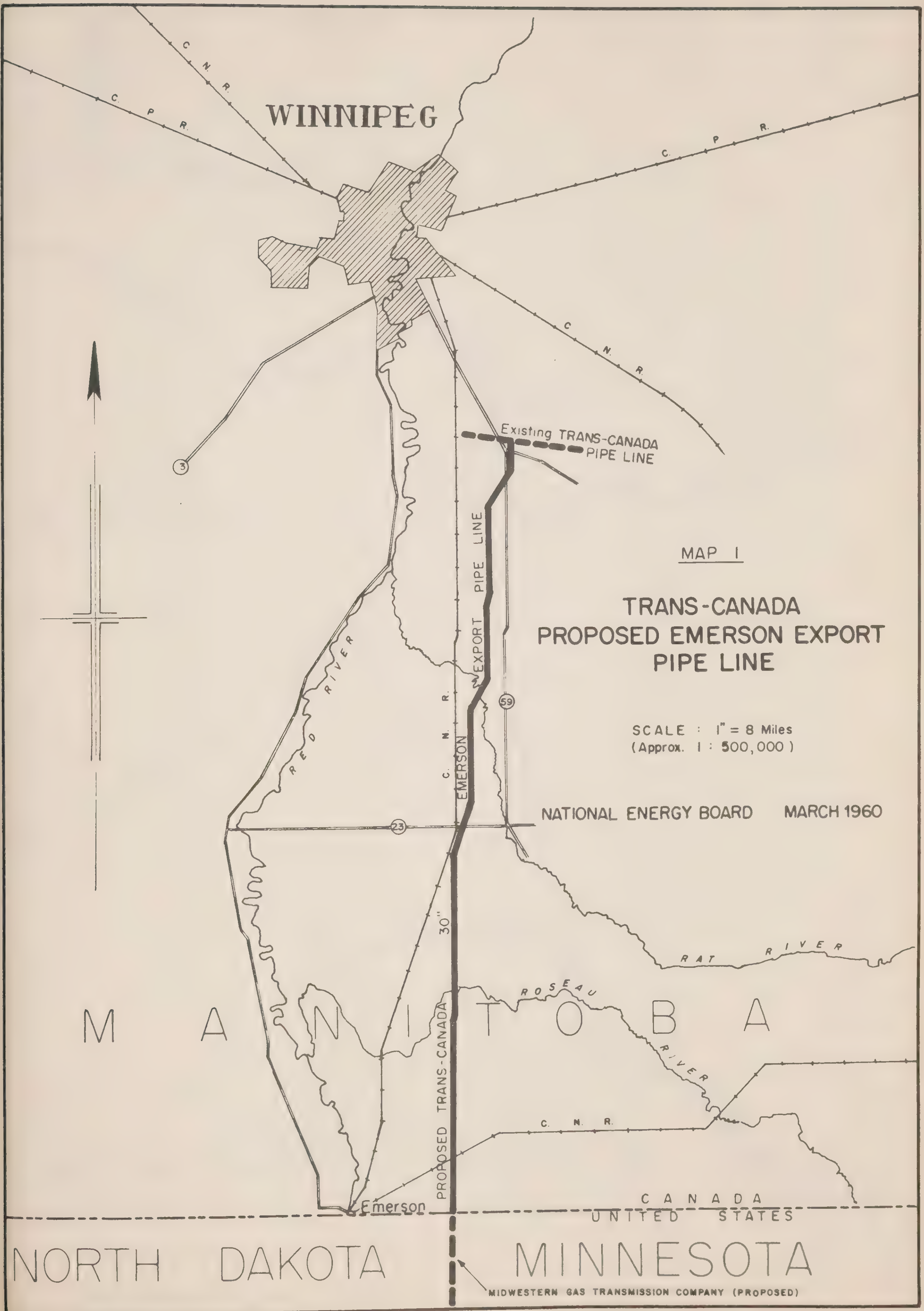
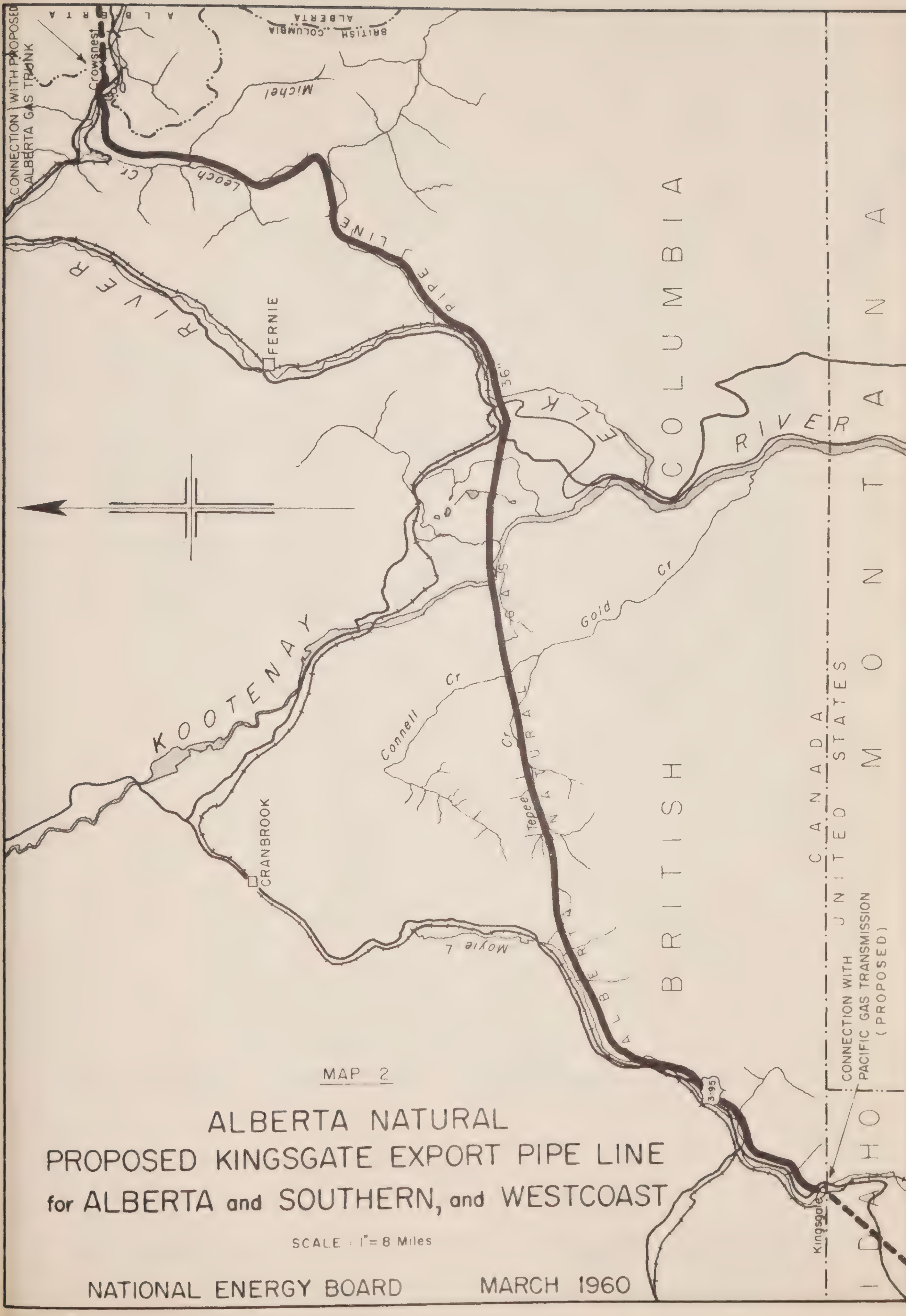

WINNIPEG
C. N. R.
C. P. R.
Existing TRANS-CANADA PIPE LINE
EMERSON EXPORT PIPE LINE
RED RIVER
RAT RIVER
ROSEAU RIVER
PROPOSED TRANS-CANADA
30"
Emerson
M A N I T O B A
CANADA
UNITED STATES
NORTH DAKOTA
MINNESOTA
MIDWESTERN GAS TRANSMISSION COMPANY (PROPOSED)
MAP 1
TRANS-CANADA
PROPOSED EMERSON EXPORT
PIPE LINE
SCALE : 1" = 8 Miles
(Approx. 1 : 500,000)
NATIONAL ENERGY BOARD MARCH 1960

5908—19

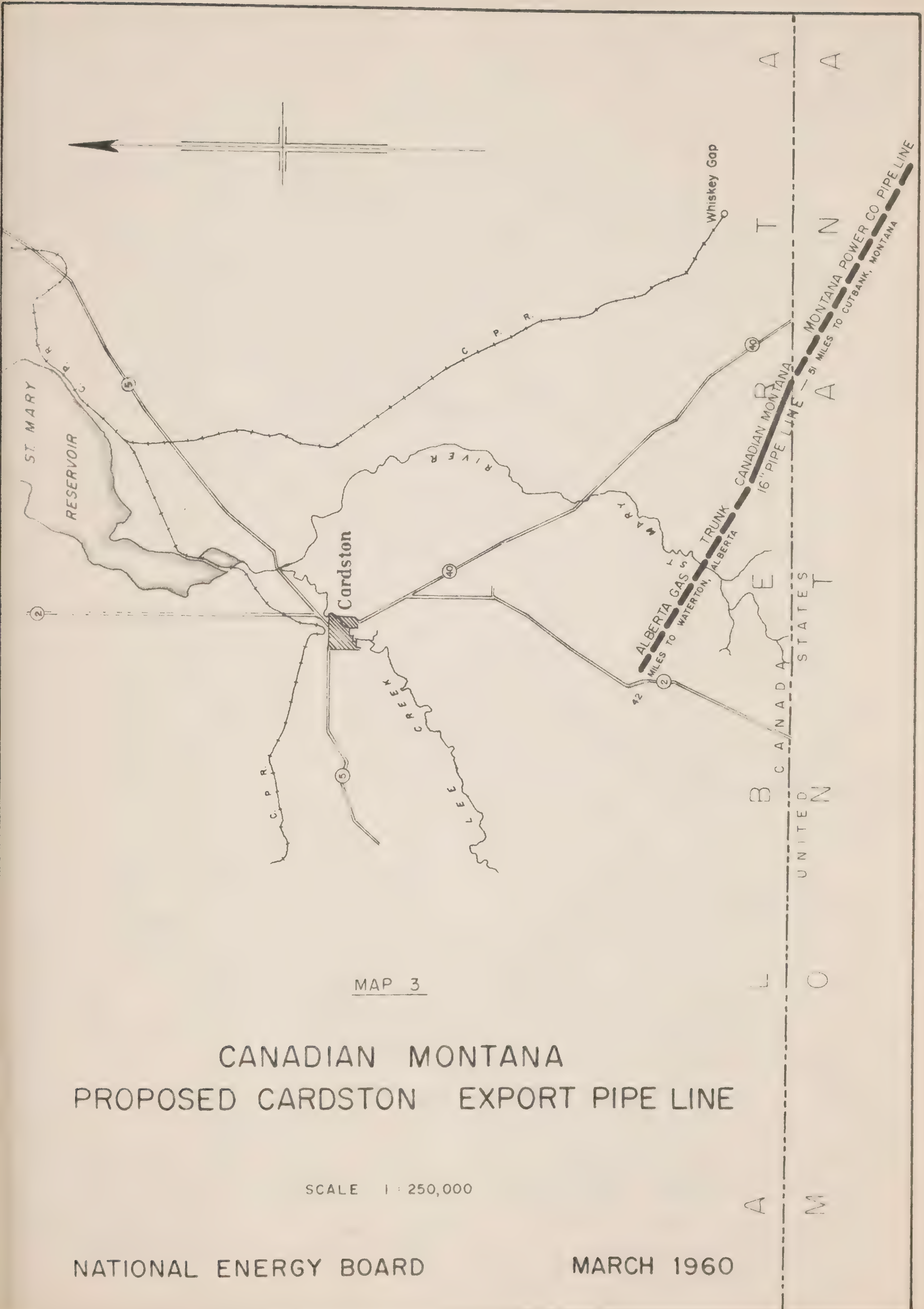


MAP 2

ALBERTA NATURAL
PROPOSED KINGSGATE EXPORT PIPE LINE
for ALBERTA and SOUTHERN, and WESTCOAST

SCALE : 1" = 8 Miles

NATIONAL ENERGY BOARD MARCH 1960

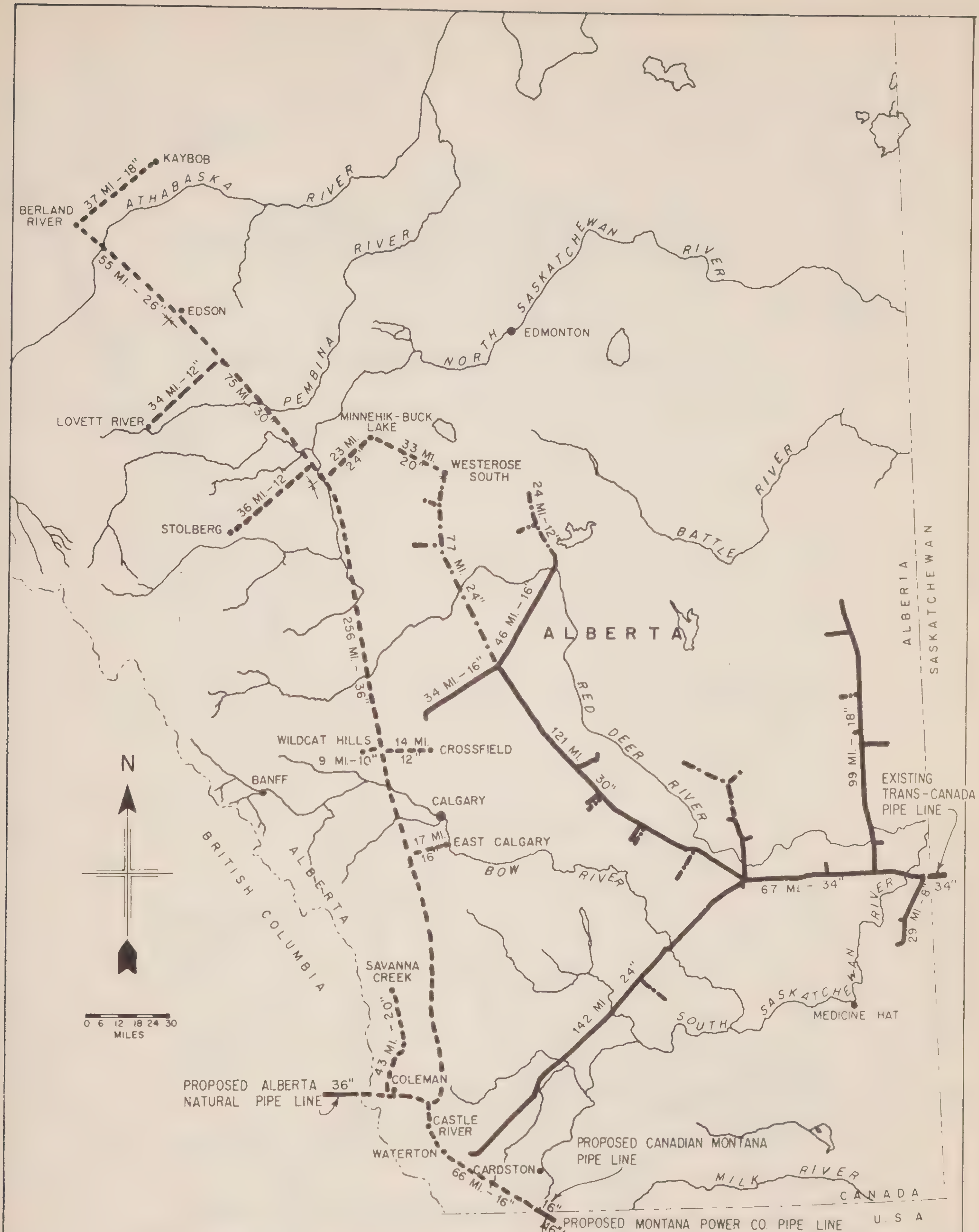


MAP 3

CANADIAN MONTANA
PROPOSED CARDSTON EXPORT PIPE LINE

SCALE 1 : 250,000

NATIONAL ENERGY BOARD MARCH 1960



LEGEND

FOOTHILLS DIVISION
PROPOSED CONSTRUCTION

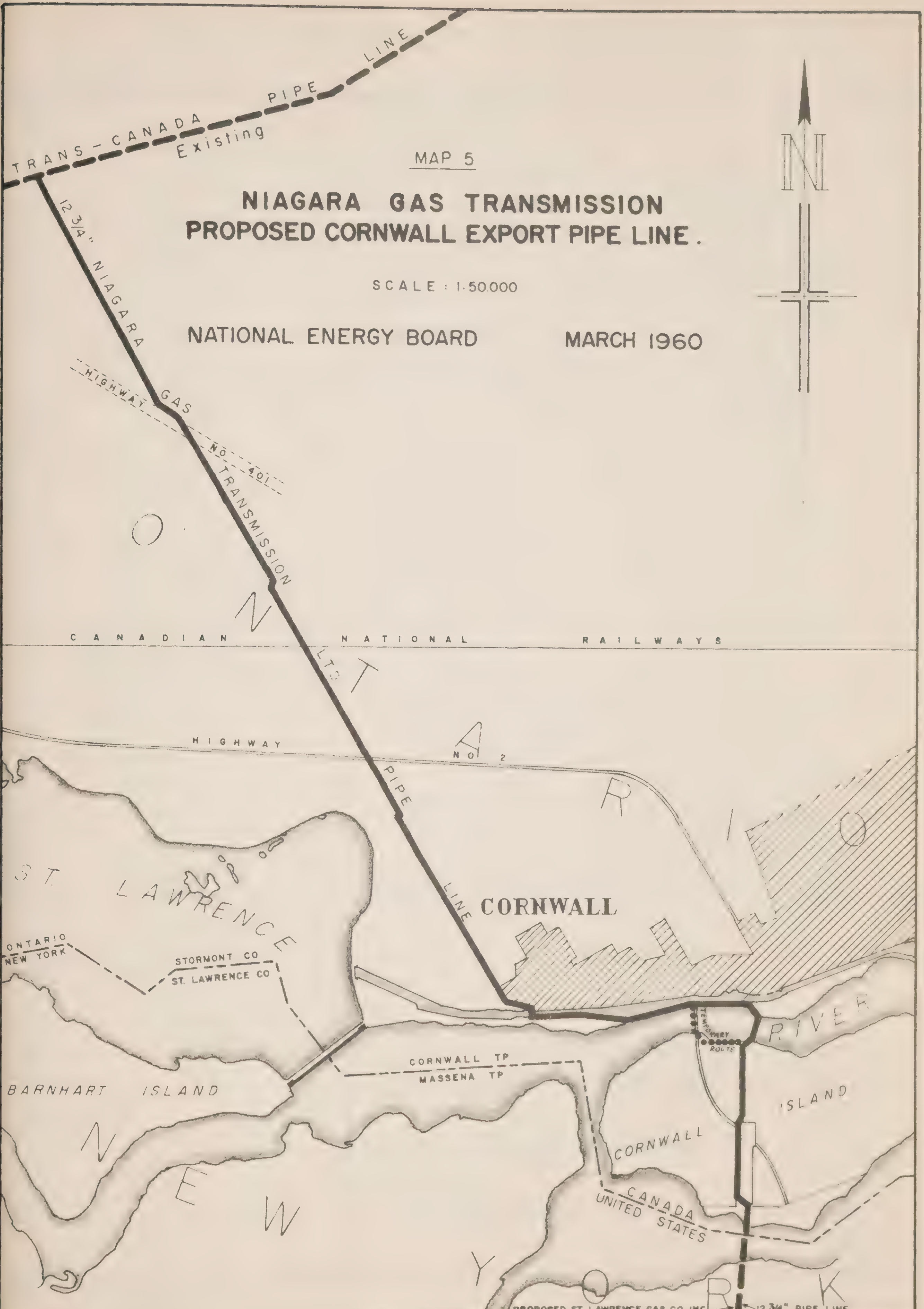
PLAINS DIVISION
EXISTING LINE
PROPOSED 1960 CONSTRUCTION

MAP 4

ALBERTA GAS TRUNK — EXISTING AND PROPOSED PIPE LINE SYSTEM

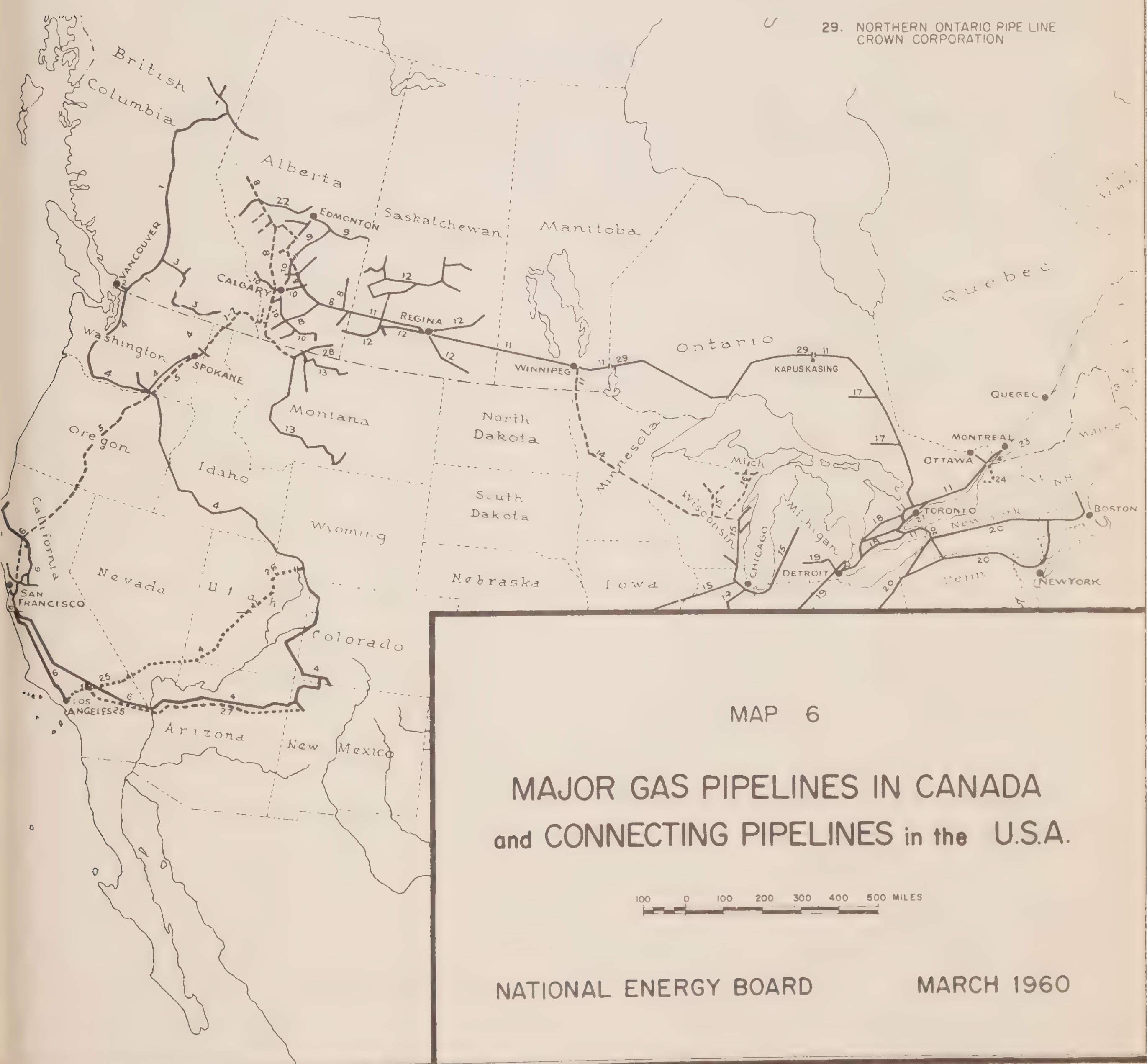
NATIONAL ENERGY BOARD

MARCH 1960


MAP 5
NIAGARA GAS TRANSMISSION
PROPOSED CORNWALL EXPORT PIPE LINE.
SCALE : 1.50.000
NATIONAL ENERGY BOARD
MARCH 1960
N
TRANS-CANADA PIPE LINE
Existing
12 3/4" NIAGARA GAS TRANSMISSION LTD PIPE LINE
HIGHWAY NO 401
CANADIAN NATIONAL RAILWAYS
HIGHWAY NO 2
ONTARIO
CORNWALL
ST. LAWRENCE
ONTARIO
NEW YORK
STORMONT CO
ST. LAWRENCE CO
CORNWALL TP
MASSENA TP
BARNHART ISLAND
RIVER
TEMPORARY ROUTE
CORNWALL ISLAND
CANADA
UNITED STATES
NEW YORK
PROPOSED ST. LAWRENCE GAS CO. INC.
12 3/4" PIPE LINE

1. WESTCOAST TRANSMISSION CO LTD.
2. B.C. ELECTRIC CO LTD.
3. INLAND NATURAL GAS CO. LTD.
4. EL PASO NATURAL GAS CO.
5. PACIFIC GAS TRANSMISSION CO.
6. PACIFIC GAS & ELECTRIC CO.
7. ALBERTA AND SOUTHERN GAS CO LTD.
8. ALBERTA GAS TRUNK LINE CO LTD.
9. NORTWEST UTILITIES LTD.
10. CANADIAN WESTERN NATURAL GAS CO LTD.
11. TRANS-CANADA PIPE LINES LTD.
12. SASKATCHEWAN POWER CORP.
13. MONTANA POWER CO.
14. MIDWESTERN GAS TRANSMISSION CORP
15. MICHIGAN-WISCONSIN PIPE LINE CO
16. MICHIGAN GAS & ELECTRIC CO.
17. NORTHERN ONTARIO NATURAL GAS CO. LTD.
18. UNION GAS CO. OF CANADA LTD.
19. PANHANDLE EASTERN PIPE LINE CO
20. TENNESSEE GAS TRANSMISSION CO
21. CONSUMERS GAS CO OF TORONTO
22. NORTH CANADIAN OILS LTD
23. NIAGARA GAS TRANSMISSION CO
24. ST. LAWRENCE GAS TRANSMISSION CO
25. PACIFIC LIGHTING GAS SUPPLY CO
26. COLORADO INTERSTATE GAS CO.
27. TRANSWESTERN PIPE LINE CO
28. CANADIAN-MONTANA PIPE LINE CO.
29. NORTHERN ONTARIO PIPE LINE CROWN CORPORATION

DASH LINES INDICATE PROPOSED CONSTRUCTION ------



MAP 6

MAJOR GAS PIPELINES IN CANADA and CONNECTING PIPELINES in the U.S.A.

100 0 100 200 300 400 500 MILES

NATIONAL ENERGY BOARD MARCH 1960

Appendix 4

STAFF ESTIMATES OF CANADIAN REQUIREMENTS FOR GAS

APPENDIX 4

STAFF ESTIMATE OF NATURAL GAS DEMAND IN CANADA, 1960 TO 1989

Six provinces were considered to be accessible to natural gas service during the period concerned. For four of these, independent estimates of demand were carried out by the staff. For the remaining two, existing estimates by other sources were accepted wholly or in part.

The independent staff estimate covered the provinces of Quebec, Ontario, Manitoba and Saskatchewan. Forecasts for these had already been submitted, both by Trans-Canada and Alberta and Southern, but because of the importance of these markets and because of discrepancies between the two forecasts mentioned, a further check was considered to be useful. Separate estimates were made in each case of domestic, commercial and industrial requirements. In the case of the last, the greater part of the work was carried out by the Mineral Resources Division of the Department of Mines and Technical Surveys.

The first step in each estimate was to forecast population growth. The base used was a forecast for all of Canada during the period 1958 to 1966, produced in September 1958 by the Economics Branch of the Department of Trade and Commerce. Since this estimate had turned out to be closer to actual experience in 1959 than most

other population forecasts then available, it was considered fairly realistic to accept the forecasts for 1960 and 1965 as well, with the exception of a single adjustment. These estimates, for the period 1960 to 1966, assumed net immigration of 100,000 persons annually. This past year's experience made 75,000 a likelier figure. Totals for 1960 and 1965 were consequently reduced by 25,000 and 150,000 persons respectively.

The Gordon Commission study, "Output, Labour and Capital in the Canadian Economy" was used to obtain provincial populations. Table 4.20, on the assumption of a net immigration of 75,000 persons annually, forecast total Canadian and provincial populations at five-year intervals over the period 1960 to 1980. Using the Trade and Commerce totals mentioned above for 1960 and 1965 as a base, growth rates shown for Canada as a whole by Table 4.20 for subsequent five-year intervals were applied, giving a new series of Canadian totals up to 1980. The ratios of provincial population to Canadian population derived from Table 4.20 were then applied to the new totals, resulting in provincial populations slightly higher than those forecast by the Gordon Commission.

From this point on, for domestic and commercial requirements, calculations were based on the method used

for the Alberta and Southern forecast. This is contained in the joint study by Stanford Research Institute and Economic Research Corporation, "Markets for Natural Gas in Eastern Canada", submitted to the Royal Commission on Energy in July, 1958. This was chosen since it provided a definite set of assumptions which could be easily checked. Trans-Canada's forecast, by contrast, was derived from estimates submitted by its individual distributors, based on facts and experience not available to the Board's staff.

Briefly, this approach was a regional one, separate assumptions being made not only for each province, but, in the case of Ontario, for three distinct marketing areas. Estimates were first made as to the proportion of the population in each region which would be economically accessible to natural gas service. On the basis of the average number of persons per household, the number of possible customers in these so-called accessible areas was derived. The percentage saturation of these markets was then estimated for two types of gas demand, that for space heating, and that for base use (which normally includes all uses other than space heating, such as cooking, refrigeration, water heating, etc). Taking the number of customers in each category thus derived, together with estimates of use per customer based on actual experience and reasonable expectation, the staff was able to

calculate total domestic requirements. Commercial demand was then taken as a fixed proportion of the domestic figure.

The Alberta and Southern assumptions, in most cases, were accepted as reasonable. Deviations, however, were made in a number of instances. The higher population estimate of Trade and Commerce was naturally used. Again, Alberta and Southern had assumed a constant ratio of 3.8 persons per household throughout the period and throughout the country. By contrast, the staff used ratios which varied from province to province and from year to year. Since few rural areas would be served with gas, census figures for metropolitan and major urban use only were used as a base. Historical figures for the main centres in each province were averaged, calculated as a proportion of the figure for Canada as a whole, and applied to estimated Canadian totals for 1960 and 1965 submitted by Central Mortgage and Housing Corporation. Since it was more or less impossible to calculate persons per household beyond 1965, the figure for that year was assumed to carry on unchanged.

On the industrial side two forecasts were made, a short-term one for 1965 and one for the longer term. With regard to the short-term, it was cbvious that there were many uncertainties and imponderables in making a forecast of industrial consumption at this early stage of the nation's market development, particularly in

Central Canada. At the outset certain areas of industry were ruled out of consideration because it was assumed that natural gas would not be a significant factor in their fuel consumption pattern. These sectors were shipping, railways, and electric power generation. After these sectors had been removed, the significant areas left in the industrial market were the manufacturing and mining industries. To narrow down the picture still further, gasoline and electric power consumption were removed from the total fuel base of both these industries, the assumption being that natural gas would not compete with or replace gasoline or electricity, and that the growth in these two energy sources would not be affected by the price, availability or convenience of natural gas. The remaining fuel base, with which natural gas was considered able to compete, was consequently made up of coal, fuel oil, natural gas and such other fuels as manufactured gas, natural gas liquids and wood.

These fuels were then converted to natural gas equivalent for the years 1953 and 1957, and the per cent that each fuel represented of the fuel base in the particular industry or sector computed. Costs of these fuels were also converted into cents per Mcf in order to compare coal and fuel oil prices with natural gas prices. Fuel growth rates for coal and oil were next computed

for the period from 1953 to 1957. In most provinces, natural gas and the other miscellaneous fuels were considered to represent such a small portion of the fuel base in those years that any calculation of growth rates would be meaningless.

Having regard to this background in fuel consumption, and to a projected rate of growth of individual industries based on population trends and related indices of industrial activity, and making allowance for the greater fuel efficiencies possible when changes are made from coal to oil or natural gas, yearly percentage growth rates were established for the period 1957 to 1965, first for the total fuel base and secondly for coal and oil. The resultant 1965 coal and oil estimates were then subtracted from the fuel base estimate, leaving the remaining demand for natural gas. Other fuels, because they represented a very small percentage of the fuel base, were ignored in the 1965 estimate and were therefore spread throughout the forecast in the major fuel sectors.

Obviously the most critical part of the forecast was in the estimation of fuel growth rates. The decisions made in this regard were based in part by objective material including the past record but tempered in most cases by value judgments. On the objective side, trends in value of shipments and quantity of production were

developed. Population growth rates both past and future were analyzed and were found, in most cases, to be very similar. Transportation costs, as well as the geographic location of individual industries and their proximity to gas pipe lines and shipping ports were considered.

The underlying assumptions involved in growth rate estimations were that industrial activity for the forecast period would proceed at the same rate as in the 1953 to 1957 period, and that the present day fuel price relationships would not change during the forecast period. Also, it was assumed that the past trend away from coal to oil and natural gas would continue into the future. Necessary to these last assumptions was the additional assumption that there would be no change in the level of coal subventions nor in world oil prices during the forecast period. It is interesting to note that coal prices have not changed significantly since 1957 - actually in some areas they have gone down slightly. Fuel oil prices that were inflated in 1957 due to the Suez crisis and which later reached a low in the summer and fall of 1957, due to post-Suez oversupply, have now returned to a more normal level, and are almost identical with 1956 prices. Making the assumption that price relationships would remain the same during the forecast period may or may not be a good assumption but,

considering the uncertainties involved in any other price assumption, this particular one was thought reasonable for forecasting purposes.

From a price point of view, comparative prices were analyzed for each fuel and for each industry, taking into consideration the price of coal and oil, and differentiating between firm and interruptible gas prices. It was in this area of fuel pricing that subjective analysis was most important and, indeed, necessary. It was felt that to establish price-volume relationships and to forecast wholly on this method was particularly dangerous and misleading, if not impossible, because of the many intangibles and undefined factors that go to make up the real cost of any particular fuel. For example, in dealing with all fuels, the question of burning efficiency can be a critical one from a cost point of view. Although there is probably less inefficiency in industrial burners than in domestic or commercial burners, one cannot assume with any real assurance that oil, coal and gas will have the same burning efficiency factor. Most companies, when making fuel cost comparisons, add certain incremental costs to coal and a lesser amount to oil because of their lesser efficiency when compared to natural gas. Consequently, one simply cannot take the delivered price of coal or oil and compare it to the delivered price of gas.

A further complication is the fact that incremental costs added to coal and oil will differ from industry to industry and within each industry, depending on how the fuel is being used and the efficiency of each individual burner in each factor or plant. Other cost considerations which affect the real cost of fuel to industry are internal handling costs, fuel processing costs, and costs involved with fuel inventories and storage. Also, certain technical factors play a part in the choice of a fuel; for example, some fuels offer better reducing characteristics than other fuels. This could be important in the smelting and refining industry. Other tangible factors that are more important in some industries than others are cleanliness, reliability and convenience. As stated previously, to put a price on these factors is very difficult from an overall industry point of view, so that one can only qualitatively estimate their overall importance in each industry and apply this qualification to the projected fuel growth rates.

These projected rates were then translated into quantities, thus forming a natural gas projection for each province in 1965. It should be noted that this was not the total coal or fuel oil forecast, but simply the total industrial natural gas forecast.

The manufacturing industry was broken down into eight sectors (animal and vegetable products, textiles and products, wood and paper products, iron and steel products, non-ferrous metals, non-metallic minerals, chemicals and allied products, and miscellaneous industries). These sectors in turn were broken down into eighteen industries. The mining sector was broken down into four mining groups, but proved to be of little importance to the natural gas forecast. All historical statistical data were taken from official unpublished Dominion Bureau of Statistics sources.

Turning to the long-term industrial forecast, growth rates were established for industrial consumption, and applied to the short-range estimates in 1965. No attempt was made to take into consideration economic business cycles or fluctuations; consequently it is the general trend line that has been forecast, not specific totals in any one year.

In order to make a realistic forecast, it was necessary to make certain broad assumptions. These were that there would be no major wars or depressions in the next thirty years, and that each province would continue to hold more or less its relative position in the Canadian economy.

At the outset the detailed method used to make the short-range forecast was rejected as a practical or

realistic method of making long-range forecasts for natural gas. It was felt that looking ahead thirty years at specific industries would be extremely difficult because of the rate of technological change and because of the many unknown and immeasurable national and international pressures that might influence Canadian industrial development. Certainly the effort that Canada makes to develop her manufacturing industries and the magnitude of simultaneous population growth in the next three decades will have an important effect on the total energy consumption. However, it is not the total energy consumption that is being estimated here, but the relative significance and importance of one of the major components within the energy framework. Undoubtedly in the next thirty years there will be broad structural changes in energy consumption. Relatively speaking, coal probably will become even less important than the 1965 estimate indicated, and fuel oil and natural gas will continue as the dominating fuels in the energy framework. In the last decade, at least, atomic energy may begin to play a part in the total energy pattern.

To make reasonable or meaningful assumptions as to the price of competitive fuels or the changing

industrial complex in the next fifteen to thirty years would be extremely difficult. Because of these difficulties two approaches have been taken in forecasting demand, neither of which depends on a great many detailed assumptions. The first approach was to establish reasonable economic correlations between energy consumption and other broad indicators that might be projected into the future with "reasonable" certainty, and then to tie the fuel consumption in some way to these projections. The second approach was to look at certain comparable areas in the United States that have used natural gas for many years and to apply their experienced growth rates, if possible, to the provinces under study. This latter approach was used only in the case of Ontario.

After examining past trends of Gross National Product (in constant dollars), total energy consumption and the volume index of industrial production as compiled by the Dominion Bureau of Statistics, there was found to be a reasonable correlation between all three of these series with only some small divergence between total fuel consumption and G.N.P. in the last decade. This is probably accounted for mainly by the rising fuel efficiencies achieved when moving from coal to petroleum product consumption. This effect, however, will become less and

less apparent as coal represents a smaller and smaller portion of the total energy consumption.

The G.N.P. forecast to 1980 prepared by Hood and Scott in the study previously referred to, "Output, Labour and Capital in the Canadian Economy" was the basis for the projection made. The medium immigration figure (75,000) and the higher productivity rate (3.25) were used to arrive at the G.N.P. estimate. The population growth rate was also derived from the Hood and Scott study, again using the medium immigration figure. The forecasted growth rate in both G.N.P. and population from 1975 to 1980 was carried on to 1989.

It must be said that although the estimation of growth rates had some basis in objective and quantitative criteria, in all cases the decisions were to some extent influenced by somewhat arbitrary value judgments. However, an examination of the literature on forecasting reveals that, for individual fuels, there is no alternative to a greater reliance on value judgments as the length of the forecast period is extended.

The resulting comprehensive staff estimate of demand for all of Canada appears in the accompanying table. That for the Province of Alberta was accepted in its entirety from the similar forecast produced by the Alberta Board, since it was felt that this body's experience

and local knowledge made its figures unassailable. In British Columbia, the estimates of domestic and commercial demand published by Westcoast were also accepted after close examination of their assumptions. Separate estimates, however, were made for industrial demand, including that for thermal power.

STAFF ESTIMATE OF DEMAND FOR NATURAL GAS IN CANADA BY PROVINCES AND CATEGORY OF USE FROM 1960 TO 1989 INCLUSIVE

TOGETHER WITH CUMULATIVE DEMANDS FOR 1963, 1980, 1984 AND 1989

(BILLIONS OF CUBIC FEET AT STANDARD CONDITIONS 14.73 PSIA, 60° F, 1000 BTU/CF)

PROVINCE	1960	1961	1962	1963	1964	1964	1966	1967	1968	1969	1970	1971	1972	1973	1974
QUEBEC															
RESIDENTIAL	7.31	9.89	12.47	15.05	17.63	20.21	22.56	24.91	27.28	29.63	31.68	34.43	36.67	39.33	41.77
COMMERCIAL	1.46	1.86	2.25	2.65	3.04	3.44	3.84	4.24	4.63	5.03	5.43	5.65	6.27	6.68	7.10
INDUSTRIAL	3.00	5.00	9.00	16.00	26.00	33.40	35.90	38.80	41.70	44.60	48.30	51.90	55.60	60.00	64.50
TOTAL	11.77	16.75	23.72	33.70	46.67	57.05	62.30	67.95	73.61	79.56	85.71	92.18	98.94	106.01	113.37
ONTARIO															
RESIDENTIAL	43.75	48.04	52.33	56.63	60.92	65.21	70.07	74.91	79.77	84.61	89.47	94.33	99.20	104.06	108.93
COMMERCIAL	8.75	9.22	9.69	10.15	10.62	11.09	11.91	12.74	13.56	14.39	15.21	16.04	16.86	17.69	18.51
INDUSTRIAL	45.60	55.20	66.90	81.10	98.40	119.30	127.16	136.50	146.10	156.30	167.20	178.90	191.40	204.80	219.10
TOTAL	98.10	112.46	128.92	147.68	169.94	195.60	209.58	224.15	239.43	255.30	271.88	289.27	307.46	326.55	346.54
MANITOBA															
RESIDENTIAL	5.98	6.59	7.20	7.63	8.44	9.05	9.66	10.27	10.67	11.48	12.09	12.80	13.51	14.21	14.92
COMMERCIAL	1.20	1.27	1.34	1.40	1.47	1.54	1.64	1.74	1.65	1.95	2.05	2.17	2.29	2.42	2.54
INDUSTRIAL	4.68	4.98	6.30	7.14	8.01	9.08	9.30	9.53	9.77	10.02	10.27	10.53	10.60	11.08	11.37
TOTAL	11.86	12.84	14.84	16.37	17.92	19.67	20.60	21.54	22.49	23.45	24.41	25.50	26.60	27.71	28.83
SASKATCHEWAN															
RESIDENTIAL	11.50	13.20	14.70	16.10	17.30	18.50	19.40	20.20	21.00	21.60	22.70	23.50	24.30	25.00	25.70
COMMERCIAL	2.50	2.70	2.90	3.10	3.30	3.50	3.60	3.70	3.80	3.90	4.00	4.10	4.20	4.30	4.40
INDUSTRIAL – FIRM	5.00	5.40	5.80	6.30	6.60	7.30	7.80	8.40	9.00	9.60	10.10	10.70	11.30	11.90	12.50
– INTERRUPTIBLE	11.00	11.10	11.40	11.70	12.20	12.70	13.60	14.90	16.00	17.10	18.20	19.30	20.40	21.60	22.60
TOTAL	30.00	32.40	34.80	37.20	39.60	42.00	44.60	47.20	49.60	52.40	55.00	57.60	60.20	62.60	65.40
ALBERTA															
RESIDENTIAL	39.60	42.30	44.50	46.40	48.20	50.10	52.00	53.30	54.50	55.60	57.50	58.50	59.50	60.60	61.60
COMMERCIAL	28.60	30.30	31.60	33.10	34.60	36.20	37.00	37.90	38.70	39.70	40.50	41.50	42.20	43.00	43.70
INDUSTRIAL – FIRM	89.10	98.90	104.50	110.60	116.60	123.00	129.80	136.70	143.80	151.30	158.90	167.00	170.00	172.80	175.80
– INTERRUPTIBLE	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
TOTAL	157.30	171.50	181.00	190.10	199.40	209.30	218.80	227.90	237.00	246.80	256.90	267.00	271.70	276.40	281.40
PIPELINE FUEL AND LOSSES	8.52	9.94	11.72	13.86	16.42	19.06	20.47	21.95	23.49	25.08	26.74	28.49	30.31	32.22	34.21
TOTAL DEMAND EAST OF B.C.	317.55	355.89	395.00	439.11	489.95	542.68	576.35	610.69	645.62	682.59	720.64	760.04	795.21	831.69	869.45
BRITISH COLUMBIA															
RESIDENTIAL	11.10	13.00	16.50	19.10	21.60	23.90	26.40	28.10	29.70	31.40	33.10	34.60	35.80	37.00	38.30
COMMERCIAL	4.70	5.40	6.50	7.40	8.10	9.30	10.20	10.90	11.60	12.20	12.90	13.40	13.90	14.40	14.90
INDUSTRIAL – FIRM	2.00	2.30	2.70	3.20	3.80	4.40	4.60	4.90	5.10	5.30	5.60	5.80	6.10	6.40	6.70
– INTERRUPTIBLE	6.00	7.00	8.10	19.60	31.30	41.30	42.00	42.60	43.30	44.00	44.80	45.60	46.40	47.30	48.20
TOTAL	23.80	27.70	33.80	49.30	64.80	76.90	83.20	86.50	89.70	92.90	96.40	99.40	102.20	105.10	108.10
PIPELINE FUEL AND LOSSES	0.80	1.00	1.20	1.70	2.30	2.80	2.90	3.00	3.10	3.30	3.40	3.50	3.60	3.70	3.80
UNALLOCATED	2.00	2.00	2.00	2.00	2.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
TOTAL B.C. DEMAND	26.60	30.70	37.00	53.00	69.10	84.70	89.10	92.50	95.80	99.20	102.80	105.90	108.80	111.60	114.90
TOTAL CANADIAN DEMAND	344.15	386.59	432.00	492.11	559.05	627.38	665.45	703.19	741.62	781.79	823.44	865.94	904.01	943.49	984.35

PROVINCE	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	TOTAL	CUMULATIVE TOTALS 1963	1980	1984	1989
QUEBEC																				
RESIDENTIAL	44.22	46.77	49.32	51.66	54.41	56.96	59.23	61.50	63.79	66.06	68.33	70.61	72.88	75.15	77.43	1,289.64	44.72	674.86	925.44	1,289.84
COMMERCIAL	7.52	7.95	8.38	8.62	9.25	9.68	10.07	10.46	10.64	11.23	11.62	12.00	12.39	12.78	13.16	219.92	8.22	115.37	157.97	219.92
INDUSTRIAL	69.40	71.60	74.30	76.90	79.60	82.40	85.30	88.20	91.40	94.60	97.60	101.10	104.50	108.20	112.00	1,671.50	33.00	988.60	1348.10	1,671.50
TOTAL	121.14	126.52	132.00	137.58	143.26	149.04	154.60	160.16	166.03	171.89	177.55	183.7	189.77	196.13	202.59	3,381.26	85.94	1778.83	2431.51	3,381.26
ONTARIO																				
RESIDENTIAL	113.79	118.67	123.65	129.03	134.11	139.19	144.65	150.11	155.57	161.03	166.49	171.95	177.41	182.87	188.33	3,389.58	200.75	1891.17	2502.53	3,389.58
COMMERCIAL	19.34	20.20	21.07	21.93	22.80	23.66	24.59	25.52	26.44	27.37	28.30	29.23	30.16	31.09	32.02	580.15	37.81	325.43	429.35	580.15
INDUSTRIAL	234.70	245.00	256.00	267.50	279.50	282.10	305.20	318.90	333.30	348.30	364.00	380.03	397.40	415.30	434.10	6,855.73	248.80	3559.20	4864.70	6,855.73
TOTAL	367.83	384.07	401.02	416.46	436.41	444.95	474.44	494.53	515.31	536.70	558.79	561.21	604.57	629.26	654.45	10,825.46	487.36	5775.50	7796.78	10,925.46
MANITOBA																				
RESIDENTIAL	15.63	16.44	17.25	18.06	18.87	19.68	20.53	21.37	22.21	23.05	23.90	24.75	25.60	26.44	27.29	475.97	27.60	260.33	347.99	475.97
COMMERCIAL	2.66	2.80	2.94	3.07	3.21	3.35	3.49	3.64	3.78	3.93	4.07	4.21	4.35	4.50	4.64	81.51	5.21	44.90	59.74	81.51
INDUSTRIAL	11.66	11.93	12.21	12.50	12.79	13.11	13.43	13.73	14.04	14.35	14.76	15.07	5.36	15.79	16.20	339.61	23.10	207.06	262.61	339.81
TOTAL	29.95	31.17	32.40	33.63	34.87	36.14	37.45	38.74	40.03	41.33	42.73	44.03	45.33	46.73	48.13	897.29	55.91	512.79	670.34	897.29
SASKATCHEWAN																				
RESIDENTIAL	26.50	27.40	28.20	29.00	29.90	30.70	31.50	32.20	32.90	33.60	34.60	[illegible]	[illegible]	38.00	38.90	781.50	55.50	466.60	597.00	781.50
COMMERCIAL	4.50	4.60	4.70	4.80	4.90	5.00	5.10	5.20	5.30	5.40	5.50	5.60	6.00	6.10	6.20	133.20	11.20	82.50	103.50	133.20
INDUSTRIAL – FIRM	13.00	13.60	14.30	15.00	15.60	16.30	17.00	17.80	18.60	19.20	19.50	[illegible]	[illegible]	21.10	21.60	391.40	22.50	215.70	288.30	391.40
– INTERRUPTIBLE	24.00	25.00	26.00	27.00	28.00	29.00	30.00	31.00	32.00	33.00	34.00	34.60	35.70	36.60	37.60	697.90	45.20	393.20	519.20	697.90
TOTAL	68.00	70.60	73.20	75.60	78.40	81.00	83.60	86.20	88.80	91.40	94.00	96.60	99.20	101.60	104.40	2,004.00	134.40	1158.00	1506.00	2,004.00
ALBERTA																				
RESIDENTIAL	62.70	63.60	64.60	65.90	67.00	68.20	69.40	70.40	71.70	72.90	74.10	75.50	76.60	78.00	79.20	1,844.80	173.20	1177.00	1461.40	1,844.80
COMMERCIAL	44.50	45.20	45.90	46.80	47.60	48.40	49.20	50.00	[illegible]	[illegible]	52.60	53.50	[illegible]	55.70	56.90	1,311.60	123.60	837.00	[illegible]	1,311.60
INDUSTRIAL – FIRM	178.60	181.50	184.80	187.90	190.90	194.40	197.60	200.60	204.40	207.90	211.50	214.50	[illegible]	222.40	226.70	5,071.60	403.10	3166.90	3977.60	[illegible]
– INTERRUPTIBLE	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
TOTAL	265.80	290.30	295.50	300.60	305.50	311.00	316.20	321.20	326.90	332.50	338.20	343.90	[illegible]	356.10	362.60	8,228.20	699.90	5180.20	6477.70	8,228.20
PIPELINE FUEL AND LOSSES	36.32	37.92	39.58	41.28	43.02	44.11	46.65	48.54	50.50	52.49	54.53	56.03	[illegible]	61.05	63.36	1,057.26	44.04	564.71	762.39	1,057.26
TOTAL DEMAND EAST OF B.C.	909.04	940.58	973.70	1007.35	1041.46	1066.24	1112.94	1149.37	1187.57	1226.31	1265.80	1306.08	1347.57	1391.07	1435.73	26,393.47	1507.55	14,971.03	19,647.22	26,393.47
BRITISH COLUMBIA																				
RESIDENTIAL	39.50	40.60	42.50	43.40	44.60	46.00	47.30	48.60	50.30	51.80	53.40	55.10	56.60	58.50	60.30	1,138.70	59.70	656.40	854.60	1,138.70
COMMERCIAL	15.40	15.60	16.50	16.90	17.40	17.90	18.40	19.00	19.60	20.20	20.60	21.40	22.10	22.70	23.50	443.40	24.00	255.70	332.90	443.40
INDUSTRIAL – FIRM	7.10	7.40	7.70	8.10	8.40	8.60	9.20	9.60	10.00	10.50	11.00	11.40	12.00	12.50	13.10	215.70	10.20	115.40	155.70	215.70
– INTERRUPTIBLE	49.20	50.10	51.20	52.20	53.30	54.40	55.70	56.60	58.20	59.50	60.90	62.4	[illegible]	65.60	67.30	1,378.30	40.70	827.90	1058.10	1,379.30
TOTAL	111.20	114.10	117.90	120.60	123.70	127.10	130.60	134.20	136.10	142.00	146.10	[illegible]	[illegible]	159.30	164.20	3,176.10	134.60	1856.40	2401.30	3,176.10
PIPELINE FUEL AND LOSSES	3.90	4.00	4.10	4.20	4.30	4.40	4.60	4.70	4.80	5.00	5.10	[illegible]	[illegible]	5.60	5.70	111.20	4.70	65.00	84.10	111.20
UNALLOCATED	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	65.00	8.00	58.00	70.00	85.00
TOTAL B.C. DEMAND	118.10	121.10	125.00	127.80	131.00	134.50	138.20	141.50	145.90	150.00	154.20	158.60	163.30	167.90	172.90	3,372.30	147.30	1979.40	2555.40	3,372.30
TOTAL CANADIAN DEMAND	1027.14	1061.68	1098.70	1135.15	1172.46	1200.74	1251.14	1291.27	1333.47	1376.31	1420.00	1464.68	1510.87	1558.97	1608.63	29,765.77	1654.35	16,950.43	22,202.52	29,765.77

NATIONAL ENERGY BOARD,
MARCH 1960.

Appendix 5

STAFF REPORT ON GEOLOGY OF CANADA RELATING TO PRODUCTIVE AND PROSPECTIVE OIL AND GAS AREAS

APPENDIX 5

THE GEOLOGY OF CANADA RELATING TO PRODUCTIVE AND PROSPECTIVE OIL AND GAS AREAS

TABLE OF CONTENTS

FIGURE 1
CANADA
PRODUCTIVE AND PROSPECTIVE
OIL AND GAS AREAS
NATIONAL ENERGY BOARD
MARCH 1960
200 0 200 400 600
SCALE OF MILES

APPENDIX 5

THE GEOLOGY OF CANADA RELATING TO PRODUCTIVE AND PROSPECTIVE OIL AND GAS AREAS

INTRODUCTION

The geology of Canada, as it pertains to the occurrence of petroleum and natural gas, may be discussed under three broad regional divisions:

1. WESTERN CANADA
   - (a) The Interior Plains
   - (b) Foothills
   - (c) Cordillera Belt
   - (d) Other Areas
2. EASTERN CANADA
   - (a) Hudson Bay Lowland
   - (b) Southwest Ontario
   - (c) St. Lawrence Lowland
   - (d) Appalachian Region
3. ARCTIC ISLANDS

An index map of Canada appears as Figure 1 on page 1.

An inspection of the table of contents will show that Northeast British Columbia has been discussed in detail.

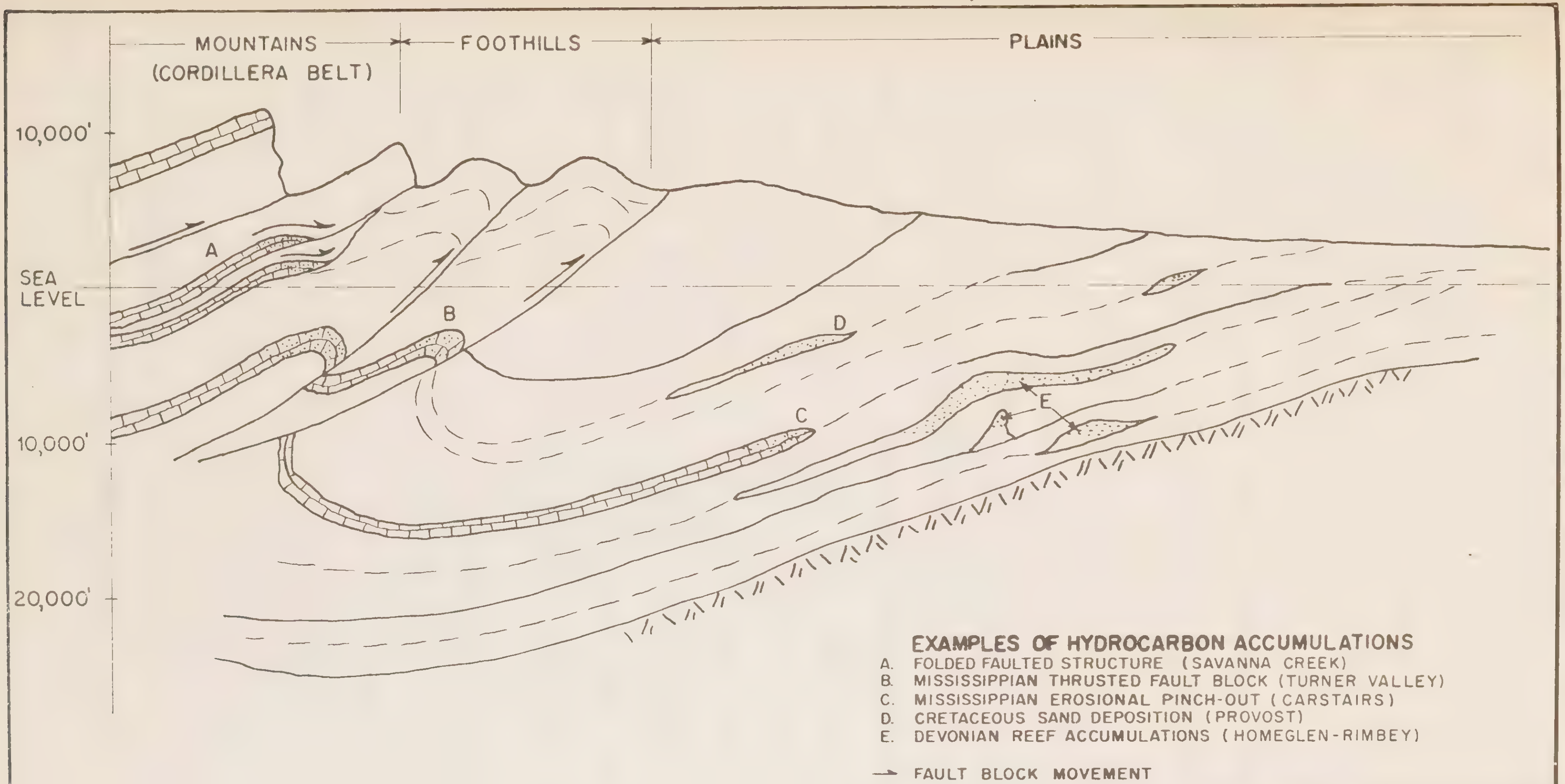
WESTERN CANADA

General

Mr. G. A. Leslie, Senior Geologist for Trans-Canada Pipe Lines Limited, gave a concise outline of the geology of Western Canada with emphasis on Alberta, at the recent hearings. He pointed out that the Western Canada basin is by far the most important in Canada, as to areal extent, volume of sediments and gas reserves.

Nearly all ages in the geological column are represented in Western Canada. The sediments are of sufficient thickness and extent to provide the various types of entrapment necessary for the retention of hydrocarbons. Those types of sediments which provide source beds for hydrocarbons are also present in large quantities. Crustal movements associated with mountain building have contributed to the formation of folded and faulted traps in the foothills and mountains. Thus all the conditions necessary for the occurrence of hydrocarbons have been met.

Mr. Leslie demonstrated with the use of a cross-section, the different types of accumulations to be found in Alberta. The variety and great number of these trapping mechanisms account for Alberta's pre-eminence and its future continuing leadership in supplying gas reserves.



WESTERN CANADA

DIAGRAMMATIC CROSS SECTION

SCALE : VERTICAL 1" = 10,000 feet
HORIZONTAL 1" = 25 Miles

FIGURE 2

NATIONAL ENERGY BOARD

MARCH, 1960

A similar type of cross-section appears as Figure 2 on page 5.

<u>The Interior Plains</u>

The great interior basin of Western Canada is bounded on the east by the Precambrian Shield and on the west by the Rocky Mountains. It continues with some variations in depth, degree of disturbance and width, north to the Beaufort Sea. The area totals some 710,000 square miles. The largest single portion is occupied by the Interior Plains. It may in turn be sub-divided, but it is beyond the scope of this report to go into further detail. The northern portions lying in the Yukon and Northwest Territories are little known except that interesting discoveries of oil and gas have been made. Certain geological horizons not represented in the southern part of the basin are present in the north and are of potential importance.

Pre-Devonian beds, except for two minor occurrences involving petroleum, have yielded no hydrocarbons to date. These early sediments have demonstrated reservoir capacity and they may be considered as a possible future source of gas.

During Devonian time, warm shallow seas provided favourable conditions for wide-spread reef growth.

Although these reefs had a limited local areal extent, they grew in almost every part of the basin, even as far north as Norman Wells. These thick porous bodies of dolomite provide very important accumulations. It will be noted that Devonian strata are not productive either in Southern Alberta or Saskatchewan.

Dr. G. S. Hume of Westcoast Transmission Company Limited, gave a detailed account of the value of Devonian reefs as reservoirs in northeast British Columbia. These beds are expected to provide the bulk of future natural gas reserves in northeast British Columbia, northwest Alberta and in the Territories.

The limestones and dolomites of Mississippian age have a rather limited occurrence in western Alberta. The erosional edge controls the accumulation of natural gas in the area north of Calgary. Mississippian beds in northeast British Columbia contain gas reserves, but in southern Saskatchewan and southwestern Manitoba, only oil is found. Strata of this age are considered to have a good future potential.

Most of the basin was emergent during Triassic time. However, thick beds were deposited in that period in the Peace River area thus providing important gas reservoirs in northeast British Columbia.

The Plains consist essentially of gently dipping sediments. These relatively stable conditions during Cretaceous time were conducive to wide-spread deposition of sand bodies, such as at Provost and Medicine Hat. The Cretaceous sands rank with the Devonian as potential sources of gas because of their known distribution. This is not the case in the northern part of northeast British Columbia where the section is almost all shale. The Cretaceous sands in most of Saskatchewan are water-bearing and hold little promise for the future.

Foothills

The Foothills Belt consists of an almost continuous band of folded and faulted strata running along the mountain front, north from the International boundary. It merges into the Liard Plateau in the vicinity of the British Columbia - Yukon border. The Mississippian beds are the most important reservoirs in this sub-region. They provide the largest single accumulations known in Canada, such as Pincher Creek and Waterton. The boundary between the Foothills and Plains in northeast British Columbia is indistinct north of the Peace River Arch. The Foothills take on a different aspect, indicating less horizontal thrusting movement and more tight folding.

The Foothills of Alberta are considered to have a very bright future for two reasons. The density of

drilling has been very low to date. The repetition of the same porous horizon by over-thrusting and faulting tends to "stack" the reservoir vertically. Reserves per cubic mile are thus much higher than in many Plains fields.

Factors which have retarded exploration in the past are:

1. Obscure relationships between geophysical interpretations and sub-surface geological conditions.
2. Difficult access.
3. Slow deep expensive drilling with related problems.
4. Economic incentive.

The Triassic and Devonian strata have demonstrated gas in commercial quantities, and can be considered as potential reservoirs. However, the Mississippian is by far the most important.

Weighing all the factors, it is considered that the Alberta Foothills provides a very great potential in new reserves, both through discovery of new pools and development of existing one-well fields. Since little

oil has been discovered in relation to the proven gas reserves, gas discoveries are expected to predominate.

Cordillera Belt

The Cordillera Belt in Alberta has already yielded one important gas discovery, the Savanna Creek field. It is obvious that accumulations within the mountains will be even more difficult to seek out and pin-point. However, it is confidently expected that exploration in this sub-region will succeed in uncovering considerable additional reserves.

The southeast interior of British Columbia has one minor but intriguing sedimentary occurrence. Paleozoic beds are covered with older Precambrian strata, associated with the Lewis over-thrust, and the Cordillera Belt. Some seepages are reported, and shows of non-combustible gas were obtained in a well drilled several years ago.

Other Areas

The Fraser Delta is composed of Tertiary beds. Sporadic drilling has found small non-commercial quantities of "marsh gas". The Islands in the Strait of Georgia, the east edge of Vancouver Island, and a portion of the Queen Charlottes have sediments of mainly Cretaceous age.

Beds of this period carry the coal measures on the Island. The strata outcropping on the Queen Charlottes contain oil shales and seeps. Several wells have been drilled with no success. Igneous intrusions are associated with these beds, and they probably baked out the volatile hydrocarbons.

The Central Interior of British Columbia is known to have sediments which may contain hydrocarbons. Vulcanism in the form of later lava flows, have partially covered these beds. Active surface exploration is currently underway over this large area, but no drilling has been done to date.

EASTERN CANADA

Hudson Bay Lowland

Paleozoic beds overlain in part by a thin veneer of Cretaceous shale and lignite constitute the sedimentary section of this outlier. Some drilling has been done but no shows of gas have been reported.

Southwest Ontario

The only significant portion of Eastern Canada is that area in southwest Ontario, west and south of the Niagara Escarpment. Beds of Cambrian, Ordovician, Silurian and Devonian age (all Paleozoic) consist of

limestone and dolomite. They were laid down under relatively stable conditions. Later gentle folding took place along an axis running north and south near London, Ontario. This probably had an influence on the accumulation of hydrocarbons.

It is noted that of the above mentioned strata, those of Silurian age are the most prolific. Interesting but very small reefs ("beehive" type) have been detected and drilled, some of which were found to be productive of natural gas. Upon depletion, these will have an important use as storage reservoirs for Western Canadian gas. It is expected that future discoveries will be made principally in the Silurian, with the Ordovician and possibly the Cambrian contributing some new reserves.

It should also be kept in mind that the prospective area of southwest Ontario (about 15,000 square miles) is slightly greater than two per cent of all the Western Canada sedimentary basin, while the volume of sediments is probably less than one per cent. Despite these confined and shallow prospecting grounds, relatively attractive quantities of hydrocarbons have been discovered and developed during the past hundred years. This is because of the local market and high well-head prices,

even though the per well output is usually much lower than in Western Canada.

St. Lawrence Lowland

This very small, restricted area on the north shore of the St. Lawrence River down stream from Montreal has indicated gas, with very small, almost negligible reserves. It is almost certain that gas from any new discoveries will be absorbed in localized rural markets.

Appalachian Region

This area has only one producing field, at Stony Creek in New Brunswick. The oil and gas accumulation is in a series of interbedded sands of Mississippian age and covers an area of about two square miles. Decline in production has indicated relatively rapid depletion of reserves.

Shows in other parts of this region have supplied incentive for sporadic exploration and drilling campaigns over the past 90 years. The Gaspe Peninsula, Cape Breton Island and the western coast of Newfoundland have reported seeps. In the latter area, a few hundred barrels of oil production have been taken.

One large oil company has had a drilling campaign under way in Prince Edward Island, New Brunswick and Nova

Scotia. Another large responsible firm is investigating the off-shore possibilities in the Sable Island area. The problem of access is not great, but the sediments are compact, indurated and usually difficult to penetrate.

It appears that at one time, there may have been extensive reservoirs. Severe crustal movement, with resultant breaching and erosion, removed the seals and allowed the hydrocarbons to escape. Deeper beds and off-shore structures have an unknown potential.

ARCTIC ISLANDS

The sediments in this Archipelago favourable for the accumulation of hydrocarbons apparently have little connection with those in other parts of Canada. It can thus be said to be a truly separate geological province. No drilling has been done, but surface indications such as thick sections of favourable rock types and piercement domes point to a potentially productive region.

NORTHEAST BRITISH COLUMBIA

Foreword

It will be noted that this region has already been mentioned in the preceding general discussion on

Canada. It was considered advisable to expand on the geology, relating it to reserves and development to date, for two reasons:

(a) The importance of the established and potential reserves of northeast British Columbia in the Canadian picture.

(b) A great deal of evidence concerning Alberta has been presented at numerous public hearings, but such has not been the case for this region.

In order to facilitate this discussion, the region has been arbitrarily divided into four Areas. The boundaries of these Areas are based partly on geological considerations and partly on the degree of development to date. They are outlined in Figure 3 on page 17. This illustration also shows one-well fields and other gas accumulations.

It will be noted that the Foothills belt has not been treated as a separate unit but rather is considered as the "hinterland" of each Area. If the Foothills were classified as an entity at this stage, they would not provide any direction in establishing trends. Only a very few tests of any consequence have been drilled in the Foothills Belt, as defined by the Canadian Petroleum Association Geological Committee.

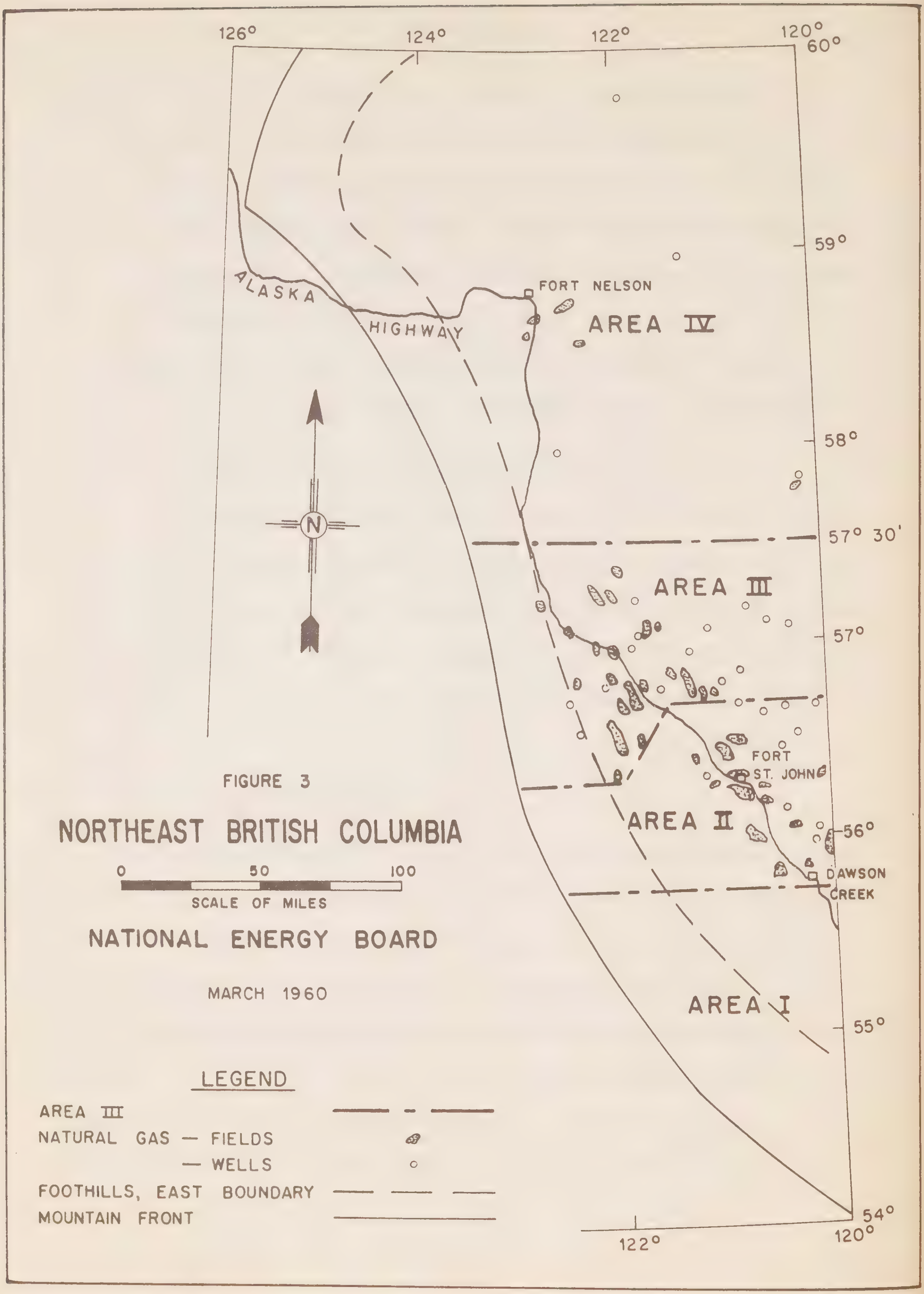
Area I

Area I includes all of the sedimentary basin south of an east-west line drawn through Dawson Creek village, and has an area of 5,000 square miles, about ten per cent of the total. A relatively small amount of drilling has been done to date and no discoveries have been credited, although several shows of gas were reported in certain abandoned wells.

Its potential is therefore virtually unknown but considered to be favourable. The great depth of the basin and the very difficult slow drilling, have placed most of this Area beyond economic reach for the time being. Sands of Cretaceous age have not proven to be of great economic interest.

Area II

Area II lies immediately north of Area I. Its north boundary coincides with that of the surveyed Peace River block, thence runs diagonally southwest to 56° 15' north latitude, thence west to the mountain front. It covers 7,000 square miles, 13.5 per cent of the total northeast British Columbia area, and has 24 per cent of the established reserves.


126°
124°
122°
120°
60°
59°
58°
57° 30'
57°
56°
55°
54°
122°
120°
ALASKA
HIGHWAY
FORT NELSON
AREA IV
AREA III
FORT
ST. JOHN
AREA II
DAWSON
CREEK
AREA I
N
FIGURE 3
NORTHEAST BRITISH COLUMBIA
0
50
100
SCALE OF MILES
NATIONAL ENERGY BOARD
MARCH 1960
LEGEND
AREA III
NATURAL GAS — FIELDS
— WELLS
FOOTHILLS, EAST BOUNDARY
MOUNTAIN FRONT

It is underlain by the west extension of the Peace River Arch, mentioned above. It includes the Boundary Lake oil field and the Fort St. John gas and oil accumulations. This Area saw the first drilling for and discovery of gas. It has the highest density of drilling both of wildcat and development categories. Gas shows and relatively easy access have contributed to this activity in the past. Fairly expensive slow drilling and geological characteristics have not made for very profitable operations. Complex faulting created small discontinuous reservoirs; there are rapid changes in rock types; the reservoir capacity in most of the horizons is quite low due to poor porosity and permeability.

Area III

Area III consists of the land from the north limit of Area II to 57° 30' north latitude. It covers 11,000 square miles, about 21.5 per cent of the total area. It includes most of the important gas accumulations in the Triassic and Mississippian and has about 59 per cent of the total established reserves. The Milligan Creek-Beatton River oil fields are also in this Area. The mid-part of Area III is characterized by mildly folded and faulted structures which have provided traps

for hydrocarbon accumulations in the above two geological horizons. The Triassic thins out near the north boundary of Area III. This pinching out provides several reservoirs. The Mississippian strata underlie all of the Area. Their potential has not been fully evaluated.

As this Area is off the north flank of the Peace River Arch, the Slave Point section of Middle Devonian age is present. This horizon is productive of gas in one well to date. Little drilling has been done to these depths. The relatively thick cover of carbonate rocks complicates the exploration of reef accumulations by geophysical methods.

Although a considerable amount of this Area is only seasonally accessible, it is currently the most active. Drilling in the Foothills Belt will be equally difficult as in Area II.

Area IV

Area IV embraces all that country north of Area III, to the Yukon, Northwest Territories boundary and is 28,000 square miles in areal extent. It is credited with 17 per cent of the established reserves.

As one travels north, the geological section becomes shorter because of the thinning in the Cretaceous

and Mississippian together with the disappearance of the Triassic. Coinciding with this, the Upper and Middle Devonian beds thicken and comprise approximately one-half of the total sedimentary section. Very little drilling has been done in this Area to date, and the density has been very low. There is currently some development drilling around certain of the more prolific discoveries but this is necessarily seasonal in character. The Lower Cretaceous section is predominantly shale and as such is not considered to have much future promise. The Mississippian has been credited with one discovery, but its potential elsewhere is not well known. The most important potential horizon in this Area is the Slave Point reef of Devonian age. Several major discoveries have been made and these indicate that the accumulations are due to reef build-up. It would appear that geophysical exploration is fairly successful in locating these anomalies. However, the nature and extent of these build-ups are at present imperfectly understood.

It appears from knowledge to date, that this Area could have only one main target, that is, the Slave Point, despite the fact that the Mississippian has demonstrated a minor amount of productivity. The Area has a very promising future as far as the Slave Point is concerned,

which off-sets to some degree the poor performance to date of the other geological strata. This does not mean that other horizons will not become important gas producers. The very small amount of drilling and development to date, has contributed relatively little to the geological understanding of Area IV and much more remains to be learned.

SUMMARY

A review of the aforementioned wide-spread occurrences of sediments clearly demonstrates the importance of Western Canada as a source of hydrocarbons. Within this large area, it is anticipated that Alberta and northeast British Columbia will retain their leadership in the development of gas reserves for some time, with the prospect that these will be augmented by discoveries in that part of the basin lying in the Northwest Territories.

Providing a good economic incentive is created and maintained, a history of activity such as Alberta has experienced should be repeated in other relatively unexplored parts of the Western Canada sedimentary basin.